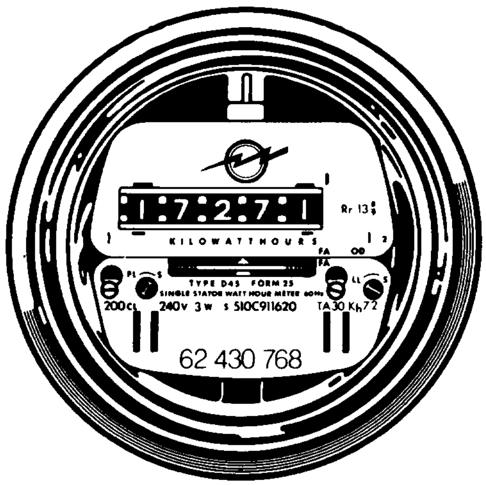
Naval Facilities Engineering Command
200 Stovall Street
Alexandria, Virginia 22332-2300

APPROVED FOR PUBLIC RELEASE



Utilities Metering

NAVFAC MO-221
November 1988

SN 0525-LP-001-3320

Distribution:
SNDL

A3	CNO	A6	CMC

(25 copies each)

FKA1C	COMNAVFACENGCOM	FKN1	EFDs

(10 copies each)

FA46	PWC LANT	FKP7	NAVSHIPYDS
FB54	PWC PAC	FT104	PWC CNET

HQ U.S. Air Force
Engineering and Services Center
Tyndall AFB, FL 32403

U.S. Army
Office Chief of Engineers
Washington, DC 20314
(DAEN-MPO)

(2 copies each)

21A	FLECOMINCH	C40	NAVOCEANCOMDET (Only Charleston, Gulfport, Newport, FPO Seattle, FPO Miami)
22A	FLECOM		
23A	NAVFORCOM		
23C	NAVRESFORDET		
24G	SUFORCOM	C84D	NAVUSEAWARENGSTADET
26B	NAVSRESFORDET	E3A	LAB ONR
26U	SFORLANTREADSUPPGRU	E3C	NORDA
26W	CARGOHANDPORTGRU	FA7	NAVSTA LANT
26Z	SHOREINTERMMAINTACT	FA10	SUBASE LANT
26NN	LANTFLESCLSHIPENGTRATEAM	FA13	NAVSUBSUPPFACLANT
26VV	SUFORREP	FA23	NAVFAC LANT
26XX	OCEANU	FA32	CBU LANT
39	CBREGIMDET	FB1O	NAVSTA PAC
45H	ENGBCO	FB13	SUBASE PAC
45J	HQB	FB28	COMNAVBASE PAC
B3	COLLEGE AND UNIVERSITY	FB36	NAVFAC PAC
C20A	ONRDET	FB41	CBU PAC
C20B	ONR	FB45	TRIREFFACPAC
C20C	NRLDET(Chesapeake Beach, Orlando only)	FB48	NAVSUPPFAC PAC
		FC1	FOCCEUR
C20G	NAVOCEANSYSCENDET	FC3	COMNAVACT EUR
C20H	DAVTAYR&DCENDET	FC5	NAVSUPPACT EUR
C28E	COMNAVBASDET	FC7	NAVSTA EUR
C31B	NAVSTADET	FC12	NAVSUPPO EUR
C31F	NAVFACDET	FD1	COMNAVOCEANCOM
C31G	NAVSHIPREPFACDET	FD4	OCEANCEN
C34B	NAVSTA ROTA DET	FF1	COMNAVDIST Washington DC
C34C	NAVSUPPACT NAPLES DET	FF3	NAVSTA CNO
FF18	NAVTACSUPPACT	FR18	NAVRESMAINTRAFAC
FF32	FLDSUPPACT	FT1	CNET
FF38	USNA	FT15	NAVU
FF42	NAVPGSCOL	FT18	CBU
FF65	SNSPO	FT20	NAVCONSTRACEN
FKA1	SYSCOMHQS	FT24	FLETRACEN
FKA8F2	NAVPRO	FT28	NETC
FKA8F5	SUBASE	FT31	NTC
FKN2	CBCs	FT37	NAVSCOLCECOFF
FKN3	OICCs	FT38	NAVSUBTRACENPAC
FKN7	NEESA	FT39	NAVTECHTRACEN
FKN10	NAVSUPPFAC	FT55	NAVSCSCOL
FKN11	NAVCIVENGRLAB	FT60	EDTRASUPPCEN
FKPlB	WPNSTAs	FT78	NAVEDTRAPRODEVCEN
FKP1J	NAVORDSTAs	FT85	TRITRAFAC
FKP3A	NAVPRO	V2	MARBKS
FKP5A	NAVSEACEN	V12	CG MCDEC
FKQ6B	NAVCOASTSYSCEN	V14	HQBN HQMC
FKQ6C	NAVOCEANSYSCEN	V16	CG MCB (less Oahu)
FR15	NAVSUPPACT COMNAVRESFOR	V17	MARCORCAMP
		V23	CG MCLB

Additional copies may by obtained from:

Navy Publications and Forms Center
5801 Tabor Avenue
Philadelphia, PA 19120

ABSTRACT

This manual provides guidance for Utilities Metering. Chapter 1 gives a broad overview and chapter 2 explains how to develop a metering program. Different types of metering are discussed in chapters 4 through 7.

FOREWORD

This publication provides information about comprehensive energy measuring and control systems which can be used to develop and implement energy management programs. The scope of the manual is limited to systems that meter flowing liquids, gases and electricity.

For maximum benefit this manual should be used in conjunction with equipment manufacturers' manuals, parts lists and drawings. In case of conflict, manufacturers' recommendations on use, care, operations, adjustment and repair of specific equipment should be followed. The manual is intended for use by facility energy officers, supervisors and maintenance personnel.

Additional information concerning procedures, suggestions, recommendations or modifications that will improve this manual are invited and should be submitted through appropriate channels to the Commander, Naval Facilities Engineering Command, (Attention Code 165), 200 Stovall Street, Alexandria, VA 22332-2300.

This publication has been reviewed and approved in accordance with the Secretary of the Navy Instruction 5600.16A and is certified as an official publication of the Naval Facilities Engineering Command.

C. M. Maskell

C. M. MASKELL
Captain, CEC, U.S. Navy
Deputy Commander for
Public Works

LIST OF EFFECTIVE PAGES

Dates of issue for original and changed pages are:

Original...0...DECEMBER 1986

TOTAL NUMBER OF PAGES IN THIS PUBLICATION IS 184 CONSISTING OF THE FOLLOWING:

Page No.	*Change No.
Title page	0
A	0
Distribution	0
Preface	0
Foreword	0
i thru xi	0
l-l thru l-9	0
2-1 thru 2-11	0
3-l thru 3-4	0
4-l thru 4-14	0
5-l thru 5-26	0
6-l thru 6-22	0
7-l thru 7-15	0
8-1	0
9-l thru 9-52	0
10-l thru 10-7	0
Reference-1	0
Glossary-1	0
Bibliography-1 and -2	0
Index-1 thru Index -3	0

*Zero in this column indicates an original page.

CONTENTS

CONTENTS (Continued)

Page

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

FIGURES

FIGURES (Continued)

TABLES

SAFETY SUMMARY

Safety is a primary consideration when operating, inspecting, or maintaining any of the systems addressed in this publication.

The first essential step is to read and understand publications associated with the systems and equipment being used. These manuals explain safe and accepted ways of installation, startup, operation, inspection, maintenance, removal, and shutdown. If you do not understand what you have read, **DO NOT** attempt to perform the intended task; get guidance from your supervisor.

The following general safety notices supplement the specific warnings and cautions appearing elsewhere in this manual. They are recommended precautions that must be understood and applied during operation and maintenance of the equipment covered herein. Should situations arise that are not covered in the general or specific safety precautions, the commanding officer or other authority will issue orders as deemed necessary for the situation.

The following safety rules are emphasized.

GENERAL

- An injury, no matter how slight, should never go unattended or unreported. Always get first aid or medical attention immediately. Should an individual stop breathing, initiate resuscitation immediately. A delay could result in loss of life.
- All signs, markings, and tags that pertain to safety measures shall be displayed prominently.
- All maintenance operations shall comply with Navy Safety Precautions for Shore Activities and Navy Safety Standards.
- All personnel should be trained and qualified in cardiopulmonary resuscitation (CPR).
- All personnel should wear safety shoes.
- All personnel should wear clothing appropriate to the job being performed. Eliminate loose clothing, which can get caught in machinery.
- Wear hardhats when required.
- All personnel should wear eye and ear protection prescribed for the task being performed.

- **DO NOT WORK ALONE.** At least one other person should be on hand to provide assistance, if needed.
- Use the correct tool for the job.
- Follow lockout and tagout procedures prescribed.

ELECTRICAL WORK

- Do not wear jewelry, including rings, bracelets, necklaces, or wrist watches.
- Do not wear jackets with metal zippers.
- Do not use metal ladders.
- Do not take short cuts. Follow all the steps recommended by equipment manufacturers.
- Be sure that rubber gloves are inspected and air tested on a regular basis.
- Use insulated tools and grounded equipment. **NEVER USE** screwdrivers or other tools with metal shanks extending through the handle.
- Use and observe tags and lockouts on circuits being worked on.

WARNINGS AND CAUTIONS

Warnings and cautions appear in equipment manuals. A **WARNING** is a situation which, if not observed, may cause loss of data, destruction of equipment, or mutilation or death to personnel. A **CAUTION** refers to a situation which, if not observed, may cause errors in data, damage to equipment, or injury to personnel.

The warnings and cautions which appear in this manual are repeated here for emphasis and reinforcement of their need to be observed explicitly. The numbers in the parentheses at the end of each item indicate the page on which it appears; for example, (4-15) refers to page 4-15.

WARNINGS

Suitable eye protection must be worn while switching or when otherwise opening circuits where an arc or flash is possible, to avoid eye injury. (6-33)

Wear rubber gloves while working on energized circuits, on any series conductors, or in a Danger Zone, to avoid electrical shock. (6-33)

WARNINGS

Wear rubber gloves while handling any items in contact with, or likely to contact, energized wires and when using live-line tools, to avoid electrical shock. (6-33)

Discharge any possible capacitance charge in disconnected cables to avoid accidental arc or discharge that might cause injury. (6-33)

Use proper type and size of fuse puller to avoid unexpected actions and risk of possible injury. (6-33)

Do not work on energized circuits unless absolutely necessary. If work must be done, another qualified person must be present with instructions to reenergize circuit if anything unforeseen occurs. (6-33)

CAUTION

Any shock, excess jarring, tipping, or turning upside down of the meter or regulator may cause internal damage, resulting in failure or improper measurement. (2-lo)

Installing meters in a tilted position may cause inaccurate meter operation and registration. (2-12)

Never short-circuit the secondary terminals of a POTENTIAL transformer. It is possible that a heavy-current flow will damage the windings. (6-21)

Never allow the secondary of a current transformer to be open circuited.

ACKNOWLEDGMENTS

The following organizations contributed information, data, or figures toward the preparation of this document.

Air System Products, Pico Rivera, CA 90660
American Gas Assn., Cleveland, OH 44131
American Society of Mechanical Engineers, New York, NY 10017
American Water Works Assn., Denver, CO 80235
Ametek, Schutte, and Koerting Division, Cornwells Heights, PA 19020
BIF, A Unit of General Signal Corp., West Warwick, RI 02893
Bailey Controls, Babcock and Wilcox, Wickliffe, OH 44092
Blue White Industries, Westminster, CA 92683
Bristol Babcock Inc., Waterbury, CT 06708
Brooks Instrument Division, Hatfield, PA 19440
Crane/Pro-Tech, King of Prussia, PA 19406
Daniel Industries, Inc., Houston, TX 77224
Datametrics, Wilmington, MA 01887
Doric Scientific Division, San Diego, CA 92123
Dranetz, Edison, NJ 08818
Engineering Measurements Company, Inc., Longmont, CO 80501
Erdco Engineering Corp., Evanston, IL 60204
Fischer and Porter Co., Warminster, PA 18974
Fisher Controls International, Inc., El Monte, CA 91734
Flow Technology Inc., Phoenix, AZ 85040
Fluidyne, A Division of EMCO, Longmont, CO 80502
Honeywell Inc., Fort Washington, PA 19034
ISCO, Environmental Division, Lincoln, NB 68501
ITT Barton Instruments Co., City of Industry, CA 91749
J-TEC Associates, Inc., Cedar Rapids, IA 52401
King Instrument Co., Huntington Beach, CA 92649
Krohne-America, Inc., Peabody, MA 01960
Kurz Instruments, Inc., Carmel Valley, CA 93924
Max Machinery, Inc., Healdsburg, CA 95448
Micrometer, Divison of Ametek, Inc., Hemet, CA 92343
Meter Equipment Manufacturing, Inc., Willoughby, OH 44094
National Electrical Manufacturers Assn., Washington, DC 20037
National Sanitation Foundation, Ann Arbor, MI 48106
Neptune Measurement Co., Greenwood, SC 29646
Pierburg Metering Systems, Inc., Totowa, NJ 07512
RCM Industries, Orinda, CA 94563
Rockwell International Corp., Placentia, CA 92670
Simpson Electric Co., Elgin, IL 60120
Sparling Instruments Co., El Monte, CA 91734
Sprague Meter Division of Textron Inc., Bridgeport, CT 06604
Square D Co., Clearwater, FL 33515
Syscon Corp., San Diego, CA 92110
Teledyne Hastings-Raydist, Hampton, VA 23661
The Foxboro Co., Foxboro, MA 02035
Westinghouse Electric Corp., Orrville, OH 44667
Yokogawa Corp. of America, Shenandoah, GA 30265,

CHAPTER 1. OVERVIEW

Section 1. INTRODUCTION

1. **BACKGROUND.** Prior to the 1970's, energy was inexpensive. Consequently, these costs were often ignored. In that era of energy affluence, inefficient practices developed. On military installations, the problem was further compounded by a general lack of metering systems. The Department of Energy reports that prior to 1973, the energy costs of a typical metal fabricating company totaled one-half of 1 percent of the total operating budget. By 1980, energy costs rose to 10 percent of the total operating costs and in other industries, energy consumed as much as 25 percent of the operating budget. With energy rivaling, or in some instances exceeding, other major cost categories, attention focused on ways to reduce the staggering expenses. Numerous programs designed to eliminate energy wasteful operations and improve efficiency were implemented nationwide. This manual emphasizes the essential role of meters in energy management programs.

2. **WHY METER.** Metering is a management tool that points the way to efficient use of utilities. Without metering, utility managers must depend on estimates and models to determine effectiveness of their utilities systems. For example, by metering, managers can identify energy waste or questionable practices, determine if steam and electric distribution lines are properly sized, and ascertain if transformers are improperly utilized. Metering pinpoints equipment in need of repair or that is being used ineffectively. Intelligent use of information generated by metering can result in savings of both energy and dollars. Identifying and eliminating operational practices or equipment that waste or inefficiently use energy will contribute substantially to successful energy management programs.

2.1 Identifying Energy Users. Many studies have been conducted to evaluate the use of meters versus "flat rates." These studies typically conclude that large savings can be achieved by metering energy use. An electric utility company in the Southwest found energy use decreased approximately 40 percent when flat rates were eliminated and individual meters installed. As a corollary, individual meters in an apartment complex were eliminated in favor of a master meter and energy consumption doubled. Not all studies identify such dramatic results, but they clearly show a potential exists for significant savings if the user is accountable for the energy he consumes.

3. **REDUCING COSTS.** Almost all electricity supplied by utility companies, because of its extensive use, offers potential dollar savings. Other energy systems such as steam, high-temperature water, and natural gas also offer opportunities for savings.

4. **ELECTRICITY MANAGEMENT.** Electrical energy costs are high and are expected to escalate. This makes it mandatory that energy saving procedures be Implemented. This task is more complicated than merely using less electricity, although lower consumption reduces cost. Since billing procedures are often extremely complicated, it is imperative that a complete

billing schedule be obtained from the utility company serving the installation. Once it is analyzed to determine what the company is charging for and why, it is possible to evaluate which changes in procedures and equipment that will achieve savings. Normally, electric utility companies use three major elements *to* bill:

- Demand
- Power Factor
- Total Energy Used

Depending upon specific billing practices, other factors, usually of lesser impact, add to basic billing charges: fuel adjustment charges, time-of-day factor, seasonal rate charges, etc.

4.1 Demand. Demand is electrical power measured in kilowatts required by a specified consumer. Demand is usually metered at specified intervals during the day.

4.2 Power Factor. Power factor is the ratio of power used to power supplied. For alternating current, the ratio normally ranges from 0.75 to 0.95.

4.3 Total Energy Used. Electric energy is the amount of electric power used over *a* period of time. Multiplying electric power by hours of use equals total energy used in kilowatt hours.

5. STEAM MANAGEMENT. Steam costs typically rank just below electrical energy costs. The cost of steam, in recent years, has increased by an order of magnitude. Its continued escalation provides a powerful incentive to pursue a steam management program. In 1985, steam costs at naval installations varied from $8.00 to $16.00 per million British thermal units (MBTU). Leaks in a steam distribution system are costly. Table 1-1 shows the cost of various sized leaks in a steam system pressurized to 100 pounds per square inch gauge (psig) with steam production costs of $10.00 per MBTU. Without adequate steam metering, it may be difficult to identify and locate areas of waste. Leaks in overhead steam lines usually can be located as the escaping steam is visible. However, when insulation is damaged or missing, the heat losses can be considerable although the cause may not be so obvious. Leaks in underground steam mains are another problem often difficult to correct. Another common cause of wasted steam is malfunctioning or incorrectly specified steam traps. A comprehensive steam trap program may give the highest payback available. Manufacturers' manuals should be consulted for suggested inspection frequency and maintenance practices. Additional waste occurs when buildings are overheated, and the excess heat is vented through windows and doors. Such losses must be identified and eliminated.

TABLE 1-1. Cost of Steam Leaks at 100 PSIG

SIZE OF LEAK	MBTU OF STEAM LOST	TOTAL COST $/MONTH*	TOTAL COST $/YEAR*
1/2"	836	8,360	100,200
7/16"	637	6,370	76,440
3/8"	470	4,700	56,400
5/16"	326	3,250	39,000
1/4"	210	2,100	25,200
3/16"	117	1,170	14,040
1/8"	62	526	6,300

*Steam costs $10.00 per million BTU

5.1 Steam and Fluid Metering. Steam, too often, is metered only at the point of production. For metering to be effective, meters are also required at the plant, in the distribution system, and at the points of consumption. This , dispersed metering is necessary to meet the objectives of metering:

- Determine plant efficiency
- Determine distribution system efficiency
- Manage the system
- To bill users

5.2 Fluid Meters. The use of fluid meters to monitor steam is prevalent. The various fluid meters are categorized by their operating principle: positive displacement meters, differential pressure meters, velocity meters, and open channel meters. Parameters metered are flow rate, velocity, temperature, or pressure at specific places and times.

5.2.1 Cost Considerations. When deciding to meter, the following items are some of the cost considerate.c]ns which must; must be addressed:

- What fluid(s) are to be metered?
- What information is required?
- What type meter will best provide the information?
- What is the initial cost of each meter?
- What type of installation-permanent or temporary?
- What special equipment is required for installation?
- Will shutdown of the system be necessary for installation?
- What ancillary or transmission equipment is required?
- How often and to what extent is maintenance required?
- How much energy loss accrues from metering?
- What are personnel and training requirements?

6. OTHER ENERGY MANAGEMENT. High-tmperature water, natural gas, potable? water, and wastewater represent systems that cost less than either electricity or steam; however, costs are not insignificant. Metering programs should be initiated to determine how effectively these systems are being used and what savings can be obtained.

6.1 High-Temperature Water. Hot water is frequently employed in applications closely related to steam. Meters may introduce problems in a hot water system that do not apply to a steam system, even though many meters can be used in either system. For example, meter induced pressure drops in a high-temperature water system can be critical if not accounted for in the original design. Should orifice meters be retrofitted in a system that was not initially designed for them, it is possible that the difference between the working pressure and saturation pressure of the fluid, sometimes called the antiflash margin, could disappear. Should the water flash to steam, results could be catastrophic, Therefore, it may be necessary to employ only meters that operate with very low or zero pressure drop.

6.2 Natural Gas. Since natural gas is often used for- heating purposes, individual. meters may result in proportional. savings as is the case with electrical energy when flat rates are terminated in favor of individual meters , Thermostats normally are installed in conjunction with a natural gas heating system.

6.3 Potable Water. Managing use of potable water does offer opportunities to conserve dollars. Similar to the situation with individual natural gas meters, installation of individual meters offers management an opportunity to establish and monitor goals. Major points of water loss can occur industrial processes and breaks in water mains. Additionally, in buildings used by large numbers of individuals, the aggregate effect of leaking faucets, valves, and toilet malfunctions result in sizable losses. In these instances, metering will help to detect and correct wasteful practices.

6.4 Wastewater. Meters used in wastewater systems are determined by the type of effluent and usage of the treated product. Meters determine the amount of fluid entering the processing plant and verify changes in the volume trends. With the advent of stringent effluent standards, management must evaluate ways to reduce the volume and improve the quality of plant discharge. If the volume of the fluid to be treated is accurately known, the amounts of chemicals to be added for co-precipitation or exchange processing of the effluent can be determined more accurately.

Section 2. PURPOSE OF THIS MANUAL

1. **INTRODUCTION.** Although many energy saving activities have been initiated, the importance of metering is not understood by many energy managers. It seems obvious that an energy accounting system is essential for control and evaluation of an management program, however some programs have relied heavily on intuition and estimates to measure progress toward management goals. Energy surveys conducted by special teams have found that such programs frequently lack the accuracy necessary for a well-run, competently managed energy program. Actions taken as a result of incorrect assumptions are no better than hit or miss decisions. This manual emphasizes the need for adequate metering and comprehensive energy management programs.

1.1 Structure of Manual. Chapters 1 and 2 present an overview of energy management and metering programs. The importance of selecting appropriate energy measuring equipment and its effective use, together with installation criteria, maintenance requirements, and establishing a viable energy management program are summarized. The remaining chapters discuss the types of meters under each major category and include the advantages and disadvantages of the meters, recommended applications, installation procedures, and maintenance requirements.

Section 3. DEVELOPING AN ENERGY MANAGEMENT PROGRAM

1. **DISCUSSION.** Energy conservation is a major part of all energy management programs, which strive to improve productivity, reduce energy expenditures, and assure an adequate supply of energy. Although the program is composed of many elements, metering is the key to a successful program. Figure 1-1 is an example of the repetitious nature of the processes involved in an energy management program. The following paragraphs describe steps needed to implement an energy management program.

1.1 Overview. An energy manager is interested in the economics of utility usage. Conservation alone usually does not eliminate waste--it only reduces it. In energy management, the prime questions are: what energy is being used; where is the energy being consumed; when is the energy being consumed and to what extent; and how is the energy being consumed. Answering these questions allows the energy manager to make decisions on replacement, repair, and maintenance that will maximize energy savings. The most efficient way to obtain the answers is through metering, which highlights improperly sized equipment, poorly functioning equipment, system losses, and inefficient scheduling. As an example, if a transformer is oversized for its load requirements, energy is being wasted. Metering the transformer is an effective means of establishing transformer load requirements.

1.2 Managerial Philosophy. In organizing the program, the manager must seek the active support of those in charge of the installation and emphasize the importance of metering. Program objectives must be clearly defined and progress toward goals adequately publicized. It is extremely important to obtain commitments from individuals responsible for implementing the program at the working level. Team effort is also necessary to achieve goals. As the program evolves, it may be necessary to restructure the organization or change procedures. This should be done promptly to maintain program momentum. And finally, adequate procedures and resources must exist to monitor and respond to the metering information.

1.3 Initial Actions. As soon as possible, obtain or make a diagram of energy systems at the installation. The diagram should identify the source and major points of energy utilization and, if available at this stage, known energy - losses. Diagrams can be refined as additional information becomes available. If all energy users are identified on the diagram, a careful evaluation may suggest optimum points for metering devices. To establish baseline values, it will be necessary to conduct an energy audit that accounts for each type of energy flow through the installation. Initially, the accuracy may not be adequate to identify all energy saving opportunities but as experience and records are amassed, this deficiency can be corrected.

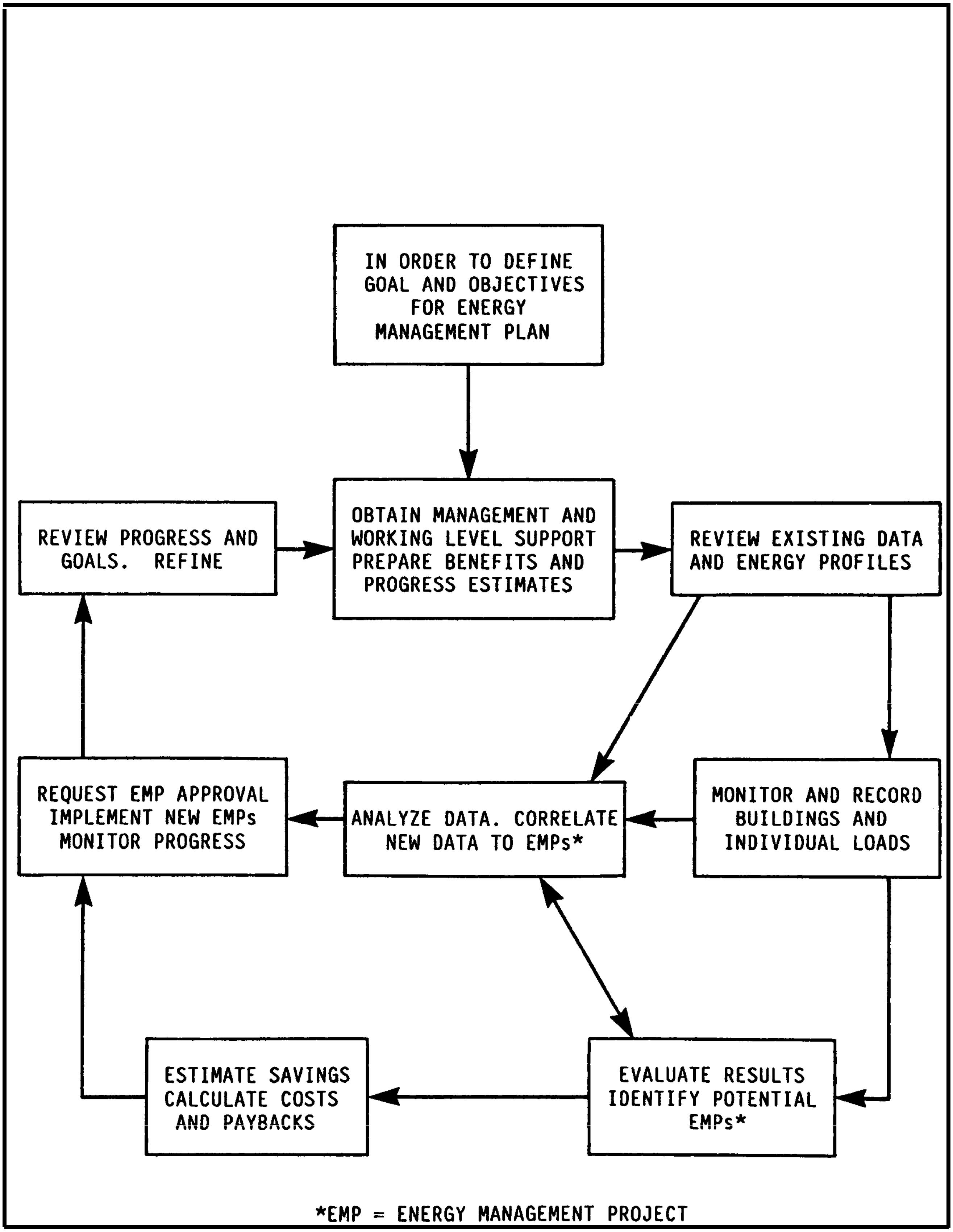


FIGURE 1-1. Flowchart of Energy Management Actions

1.4 Minimize Costs. After deciding where meters will be located and what physical properties will be measured, meter selection charts should be used to evaluate possible choices. After tentative meter selections have been made, manufacturers can provide information which will aid you in deciding on the final selections from the standpoint of total cost, derived information, and compatibility with future developments.

CHAPTER 2. DEVELOPING A METERING PROGRAM

Section 1. METER SELECTION

1. **METER SELECTION.** Selection of metering equipment consists of much more than purchasing a meter compatible with the system to be metered. Selection of metering equipment for electricity is greatly simplified as the operating principles of electrical metering devices exhibit little variation compared to fluid metering equipment. Purchasing electric metering equipment basically requires an identification of measurements to be made, the parameters of the system, a decision on remote metering, and selection of a meter that fulfills these requirements. Metering of fluid systems requires additional effort. Figure 2-1 is an example of the system information necessary to optimize a fluid type meter selection. Figure 2-1 used in conjunction with Table 2-1 is an example of an iterative process for proper meter selection. Another selection method recommends the factors shown in Figure 2-2. Whatever criteria selected, they must be tailored to the specific installation to ensure that any problems are fully highlighted in the process. The individuals involved in the selection process must be knowledgeable of the sources to be monitored, the information required, and the capability of the meters being evaluated. Another major consideration is the purpose of the meter: control or accountability. Once the information contained in figures 2-1, 2-2, or other criteria is available, a tentative meter(s) selection can be made. At this point, manufacturers of this type meter should be consulted. Although most manufacturers provide extensive cooperation, their claims should be thoroughly evaluated to insure that a particular choice is optimum for the intended application.

1.1 Permanent and Portable Meters. In establishing an energy management program, the use of permanent or portable meters shall be evaluated. Meter locations must be evaluated individually to ensure accounting for all factors pertinent to meter installation and maintenance.

1.1.1 Fluid Meters. Intrusive flowmeters, particularly differential pressure and positive displacement types, always have some degree of pressure loss associated with their operation. Consequently, if continuous data recording is not required, portable insertion meters may be used for temporary metering. If continuous metered data is required, but pressure losses are a concern, non-intrusive meters should be considered, despite their greater initial costs. Because most permanent meters are pipe size specific, costs increase in proportion to pipe size. Insertion meters do not generally increase in price as pipe size increases, and are generally more economical for larger pipe sizes. Figure 2-3 shows a cost comparison of a permanently installed orifice plate meter versus an insertion type meter. Typically, the cost advantage crossover occurs between the 6- to 8-inch pipe size.

1.1.2 Electric Meters. The usual distinction between panel (permanent) and portable electric meters is whether they are fastened securely to the facility or capable of being hand carried. Most electric meters are made in both

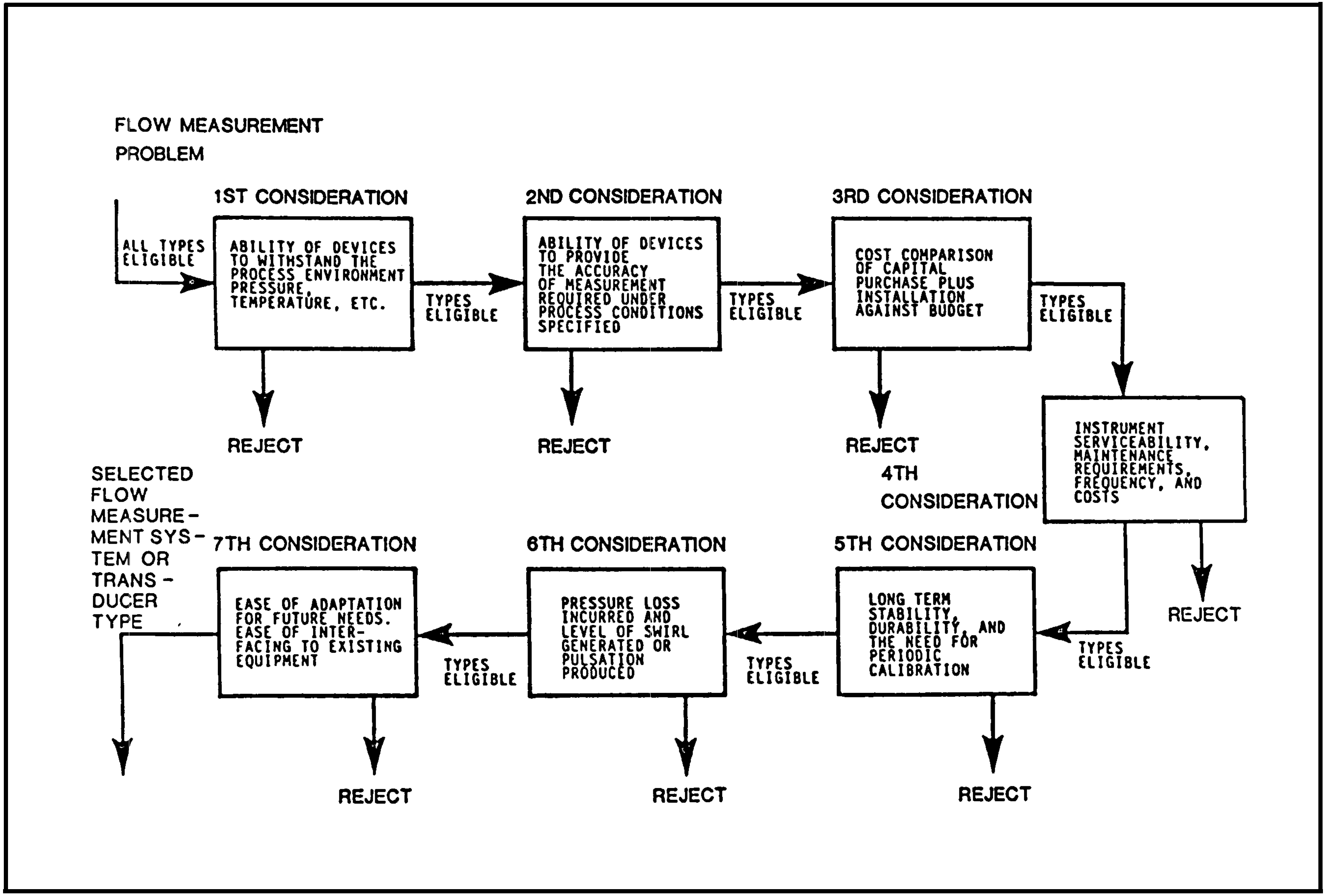


FIGURE 2-1. Iterative Approach to Flowmeter Selection

1. What medium is to be measured?

2. Will meter indications be used for process control or energy accounting?

3. What physical measurement will be used to determine the flow rate?

4. What are accuracy requirements?

5. Are physical space limitations a factor in mounting the meter and any associated equipment?

6. Are there any environmental conditions at meter site that would limit meter selection?

7. Can the media flow be turned off for meter installation or must it be a hot insertion?

8. Must meter maintenance be accomplished with the line hot?

9. What range of flow must be measured currently and what is predicted flow in the future?

10. Will data be obtained by direct reading or remote monitoring? If direct reading, is remote monitoring contemplated in future? Ensure meter is compatible.

11. Is the media flow steady, intermittent, or pulsating? Is there a full pipe flow?

12. Can a portable meter be used that will provide adequate measurements and what are the cost advantages?

13. Identify potential meter selections that meet the requirements listed.

14. Contact several manufacturers for recommendations.

15. Ensure such recommendations allow comparisons between various candidates pertaining to purchase and installation costs, operational limitations, maintenance requirements, training requirements, costs related to operation of the meter in the media (pressure drop), and all other factors important to the specific installation being evaluated.

FIGURE 2-2. Alternate Factors for Meter Selection

TABLE 2-1. Characteristics of Flowmeters

Type	Turndown Ratio W/O Span Adjust	Accuracy	Permanent Pressure Loss	Signal Response Attributes	Data Signal Methods	Fluids	Effect of Increased Viscosity	Advantages	Disadvantages	Cost of Installation/ Annual Maintenance**
Differential Pressure Orifice Plate	4:1	±0.6% to 1% of full scale	High	Square root	Analog Electronic Pneumatic	Liquid Gas	High	Easy to install Low cost Well understood industry standard	Not for dirty or corrosive fluids High maintenance Large unrecovered pressure drop Line must be secured to install or replace plate	2*/4
Flow Nozzle	4:1	±1% of full scale	Medium to High	Square root	Analog Electronic Pneumatic	Liquid Gas	High	Low maintenance High flow High velocity	Moderate cost	3/3
Venturi	4:1	±1% of full scale or better	Low	Square root	Analog Electronic Pneumatic	Liquid Gas	High	Low maintenance High flow High velocity Good for dirty fluids and slurries	High cost Big and heavy in larger pipe sizes	4*/3
Averaging Pitot Tube	3:1	±1% of full scale	Low	Square root	Analog Electronic Pneumatic	Liquid Gas	Limited	Low maintenance Easy installation Low cost Insertion type available	Does not sample full stream Tends to clog	1*/3
Variable Area (Rotameter)	5:1 to 12:1	±0.5% of flow rate to ±10% of full scale	Medium	Linear Logarithmic	Analog Electronic Pneumatic	Liquid Gas	Medium	Low cost Direct indicating No power required Minimum piping requirements	Must be vertically mounted Gas use requires minimum back pressure Requires accessories for data transmission	1*/1
Turbine	10:1 to 50:1	±0.25% of liquid flow rate ±1% of gas flow rate	Low	Linear	Analog Electronic Digital	Liquid Gas	Medium to high	Easy installation Insertion type available High accuracy	Moderate maintenance High relative cost	5/2

TABLE 2-1. Characteristics of Flowmeters (Cont'd)

Magnetic	10:1	±0.5% of reading to ±1% of full scale	None	Linear	Analog Electronic Digital	Liquids Corrosives Slurries Sludges	None	Low maintenance Unaffected by pressure or temperature Insertion type available	Moderate to high cost Fluids must be conductive Not for gaseous fluids	4/1
Positive Displacement	10:1 to 20:1	±0.5% of liquid flow rate ±1% of full scale for gas	High	Linear	Analog Electronic Pulse	Liquids Gases	High	Ideal for viscous liquids No upstream pipe requirement	Mechanical wear of parts Sensitive to dirty flow Larger sizes big and heavy	4/1
Vortex	10:1	±1.0% of rate or better for liquids ±2% of rate on gases	Medium	Linear	Digital Analog Electronic	Liquids Gases	Low	High accuracy No moving parts Low to moderate maintenance costs Easy to install	Piping requirements are severe Not recommended for Reynolds Numbers < 10,000 Moderate to high cost	5/1
Ultrasonic Transit Time	20:1	±1% of flow rate to ±5% of scale	None	Linear	Analog Electronic Digital	Liquids	None	No obstruction in pipe Gas versions available Clamp-on version available	Relatively clean liquids only When slurries < 2% by volumne, field calibration required	3/3
Ultrasonic Doppler	10:1	±5% of full scale or better	None	Linear	Analog Electronic Digital	Liquids	None	No obstruction in pipe Inorganic slurries and aerated liquids Clamp-on version available	Requires < 25 ppm suspended particles or bubbles When slurries < 2% by volumne, field calibration required	3/3
Target	4:1	±0.5% to ±5% of full scale	Low	Square root	Analog Electronic Pneumatic	Liquids Gases	Medium	No moving parts Relatively inexpensive Good for hot, tarry or sediment bearing fluids	Piping requirements are severe	4/1
Weirs and Flumes	Weirs 100:1 Flumes (Parshall) 50:1	±2 to ±5% of full scale	Very low	Varies	Frequency Analog Electronic	Liquids	Very low	Ideal for waste and water flows Flumes self-cleaning, and low head loss	Weirs-require cleaning	5/1

* - W/O analog or pulse output

** - Installation/Annual Maintenance Cost Codes: 1: < $500; 2: < $1,500; 3: < $2,500 4: < $3,500 5: < $4,500

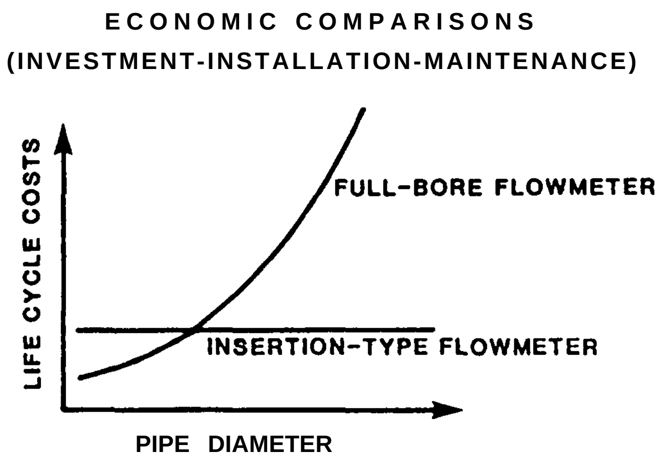


FIGURE 2-3. Flowmeter Type/Cost Comparison

panel and portable models. The following list indicates model availability.

- Ammeters--panel and portable.
- Kilowatthour--panel and portable.
- Multimeter--portable.
- Power factor meters--panel and portable.
- Voltmeters--panel and portable.
- Watt/demand meters--panel and portable.

1.2 Incremental Installation of Metering Systems. If the management plan envisions a complete metering system consisting of metering devices, data recording, and central or remote control capabilities, it is probable that the system will have to be installed on an incremental basis. If so, the meter criteria (figures 2-1 or 2-2) must take this into account to ensure equipment for each phase is fully compatible and interfaces with the components required to complete the system.

Section 2. METERING CRITERIA

1. **METER INSTALLATION CRITERIA.** Meters and ancillary equipment should be installed in new or retrofit construction to facilitate management of utilities. Meters shall be installed when the following criteria are met:

(a) New construction—New facilities should be provided with electric, water, and natural gas meters, as appropriate. Steam meters should be provided for new facilities where the annual energy cost component of steam will exceed $50,000.

(b) Energy retrofit programs--Meters shall be installed on Energy Conservation Investment Program (ECIP) projects if the total project SIR is at least 2.5, including the cost of the meters, and if the cost of the meters does not exceed 10 percent of the total cost of the project. Meter costs shall include both hardware and installation. If meter installation cannot be cost-justified for one facility, combining a number of facilities in the analysis may warrant meter use. For Energy Technology Applications (ETAP) projects, meters should be included if desired by the activity and Claimant. Figure 2-4 is an example of how to evaluate a meter installation using these criteria.

(c) Energy-Converting Devices: All energy-converting devices with outputs greater than 20 MBTU/hr or 1,000 kW, such as boilers, turbines, and generators, shall be metered. Metering both input and output is desired, but where cost considerations limit metering to input or output only, select the most useful and cost effective.

(d) Customer Requirements: Meters may be installed at the customer's request for energy accountability or for project validation.

(e) Public Works Center (PWC)/Public Works Department (PWD) Requirements: Meters shall be installed by the PWC/PWD for billing and energy management.

(f) Preinstalling Meters: Hardware and plumbing may be installed so that portable meters can be used later. If criteria to install permanent meters are not met, the criteria shall be reapplied for portable meter preinstallation. Portable meters can then be installed for spot checking and profiling. Portable meters can also be used to determine whether proposed meter sites meet criteria.

2. **METER LOCATION CRITERIA.** Meters must be in strategic locations that will provide energy managers with adequate information to control their utility systems. They shall provide information to determine when load shedding is required, identify situations where energy losses can be avoided, verify that procedural changes will result in decreased utility costs, and allow metering of tenants. In selecting locations, preference shall be given to locations that are clean, well-lighted> and minimize damage possibilities. It is also important to select sites where excess heat or other potential causes of

Example:

A project is approved to replace 50, 1,000-watt mercury lamps with 50, 400-watt sodium lamps in a hangar. Project cost is $10,500 with discounted benefits of $34,969 (project information). Determine if a meter can be included in this project within the quidelines of paraqraph 1 (b).

Procedure:

A. Compute SIR, both with and without a meter, and evaluate results.
B. Calculate cost for the completed project and ensure meter costs are equal to or less than 10% of this value.
C. If preceding step is unsuccessful, reevaluate, combining additional facilities.

Known:

Cost of installed meter is $2,000.
SIR = Discounted Benefits/Project Cost; SIR must be greater than 2.5.

Procedure A: SIR Test:

SIR (No meter) = $34,969/$10,500 = 3.33	SIR of 3.33 2.5
SIR (With meter) = $34,969/$12,500 = 2.80	SIR of 2,80 2.5

SIR remains greater than 1; project will not be jeopardized by meter.

Procedure B: Calculation of 10% Criteria:

Since the meter cost ($2,000) is greater than 10% of the project cost $1,050) a meter can not be included in this project,

Procedure C: Meter Justification for Entire Hangar:

Excluding electric costs for the lamps, the daily energy load is determined to be 60kW for 8 hours and 35 kW for the remaining 16 hours.

Costs per year: 1,040 kWh/day x 260 days x 0.06/kWh = $16,224

$16.224 + $4,992 = $21,216

10% x $21,216 = $2,121

$2,121 is greater than $2,000 (meter cost); therefore, one meter for the entire hanqar is justified as it meets both the SIR and 10% criteria,

FIGURE 2-4. Application of 10 Percent and SIR Criteria to Meter Projects

faulty readings are absent. The following paragraphs contain recommended locations for meter installation; however, if unusual circumstances exist, some deviation is acceptable providing the metering results do not degrade the utility manager's capability to effectively manage.

2.1 Electrical Utilities. Meter locations are as follows:

(a) Meters shall be located at sources of supply, major substation feeders, major loads (piers, industrial loads, and hospitals), and locations where tenant activities can be metered.

(b) Metering shall have the capability of monitoring demand in kilowatts, and total energy in kilowatthours.

(c) Meter taps shall be installed at strategic locations so that portable meters can be used to monitor loads for short intervals.

2.2 Steam Utilities. Meter locations are as follows:

(a) Meters shall be located at sources of supply, the supply end of trunklines, major loads (piers, industrial loads, and hospitals), and locations where tenant activities can be metered.

(b) Trunkline meters shall be of the turbine meter type and have the capability to compensate for pressure and temperature.

(c) Meters taps shall be installed at strategic locations so that portable meters can be used to monitor loads for short intervals.

2.3 Gas Utilities. Meters shall be located at sources of supply, major loads (industrial loads and hospitals), and locations where tenant activities can be monitored.

2.4 Water Utilities. Meters shall be located at sources of supply, major loads (industrial loads and hospitals), and locations where tenant activities can be metered.

3. PRIORITY OF METER INSTALLATION. Meters shall be installed on a priority basis, that rank projects according to the potential savings of utility dollars. Although installations must be evaluated individually, a typical Installation would rank energy costs as follows, which in turn establishes priority ranking for meter installation:

(a) Electricity

(b) Steam

(c) High-Temperature Water

(d) Natural Gas

(e) Potable Water

(f) Wastewater

Section 3. MAINTENANCE

1. **MAINTENANCE AND MAINTENANCE RECORDS.** Since any metering program relies on accuracy of the information derived, a maintenance, inspection and calibration program must be established. Meters must be tested and calibrated prior to installation and subsequently on a schedule recommended by the manufacturer. Meters monitoring energy sources entering the facility must be calibrated at least annually. Figure 2-5 is an example of a maintenance record form for utility meters. This form can be revised to provide salient information for other types of meters. Skilled technicians must be assigned to maintain and service meters and auxiliary equipment. Personnel without specialized training must be discouraged from trying to correct any problems encountered due to the high cost of this equipment. If skilled maintenance employees are not available, one alternative is a maintenance service contract.

2. **CALIBRATION RECORDS.** Records of all maintenance, inspection, and calibration actions must be kept to verify the status and accuracy of the meter. Historical records should be reviewed to determine whether calibration is performed frequently enough to maintain meters in good working order. Certain applications may be critical and require more frequent calibration. Conversely, historical records may show that the meters do not need calibration as frequently as presently scheduled.

MANUFACTURER	SERIAL NO	MAKE	MAKE	SIZE
DATE INSTALLED			STYLE	
INSINUATION RECORD			TEST AND REPAIR RECORD	

INSTALLED DATE	INSTALLED RDG	LOCATION		SEASONS FOR REMOVAL	DATE	RDC	DATE	FUN FLOW	METER FLOW	MAX FLOW	% ACCURACY BEFORE	% ACCURACY **AFTER**	COST OF REPAIR **MATL**	COST OF REPAIR **LABOR**	TESTED BY	**REMARKS**

FIGURE 2-5. Example of a Maintenance Records Form

Section 4. RECORDKEEPING

1. **METER DATA.** In evaluating the progress of any energy management program, a chronological record of performance must be retained for reference and comparison purposes. Most meter recording devices print information on either a strip chart or as a column of alphanumeric symbols. Numerous computer programs are available that calculate and display trends, variations, and progress toward final goals. If a computer is not available, information can be compiled using a handheld calculator. If meters are not equipped with a recording device, it will be necessary to determine how often the meter information shall be recorded. A form must be developed (Figure 2-6) that will adequately identify and record the pertinent information for subsequent analysis. Recording devices that provide a continual or variable time interval record of meter measurements are essential to an energy management program; but data must be reduced, analyzed, and acted upon regularly to be of any benefit.

1.1 Data Collection. Data must be collected on a regular and consistent basis. Regular data collection keeps personnel familiar with "normal" usage data and helps create a basis or history of utility consumption. Regular data collection is essential to prevent backlogs of raw data that must be reduced.

1.2 Data Reduction. Raw data must be reduced to summarize metered information. It can be tabularized, averaged, maximums and minimums calculated, and graphed to show usage trends and demonstrate the value of energy conservation actions. Using statistical techniques, such as multiple linear regression, data can also be used to construct utilities consumption models . Multiple linear regression produces a utilities consumption model equation by establishing the validity of the relationship between variables that affect utilities consumption (independent variables) and actual utilities consumption (dependent variable). By establishing which variables actually affect utilities consumption, changes in utilities consumption can be understood and anticipated.

1.3 Problem Identification. Regular data collection and analysis allows operating personnel to become familiar with "normal" meter operation and to recognize unusual readings or conditions. This is essential to timely maintenance.

1.4 Reporting. Metered data serves no purpose if it is not distributed to personnel who can effect changes. Consequently, each command should establish a distribution list for meter reports. The distribution list should include the commanding officer, production officer, public works officer, department heads, and work center and production managers. Command and management support is an absolute requirement for a successful metering program.

METER RECORD

❑ Gas ❑ Water ❑ Elec ❑ Steam ❑ Other ______________________

Consumer ______________________________ Location ______________________

Meter I.D. ______________________________ Measured In ____________________

Frequency of Meter Recording ____

Date	Time	Reading	Init	Date	Time	Reading	Init

FIGURE 2-6. Example of Form to Record Meter Data

Section 5. CERTIFICATION OF PURCHASED UTILITIES

1. **METER CALIBRATION CERTIFICATION FOR PURCHASED UTILITIES.** Purchased utilities are a significant cost to Navy activities. Because the utility company usually owns and maintains the utility meter, the activity often has no direct way to verify charges. This problem has been complicated by the advent of digital recording meters that provide no visual readout. Following are methods of verifying charges for purchased utilities:

1.1 Redundant Metering. Utility bill verification at the 100 percent level can be achieved by redundant metering. This requires installation of Navy owned meters in series with those of the utility company. Depending on utility service configuration, one or more meters are required for each purchased utility. Cost of redundant metering must be evaluated with respect to potential benefits before redundant meters are installed. Redundant meter costs include cost of meters and installation, cost of outages to install the meters, cost of reading and analyzing the additional meters, and cost of annual maintenance and calibration.

Most activities have electric meters at major substations. By calculating energy balance, the activity can verify whether utility charges are correct. This option is limited to the extent that meters are installed at an activity, but, because the meters can be used for energy management and in-house billing, this type of redundant metering may be more cost effective than a single redundant meter. Meters should be sited at major trunks to minimize the number of meters required.

1.2 Verification by Historical Usage Data. Utility bills should be checked for discrepancies by comparing historical usage rates to present consumption. The following should be considered:

(a) Based on past billing records, set high and low limits for utility consumption and compare the utility bill to the limits. This is accomplished by evaluating past data for trends and usage patterns and developing a prediction of what utility consumption should be during a specified interval. Significant deviation from predicted usage should be investigated. Multiple linear regression techniques may be useful in developing predictions of utility consumption.

1.3 Utility Procurement Contracts. Utility procurement contracts should be written to meet verification requirements. Utility contracts are renewed yearly and can be modified to achieve this. Contracts should include:

(a) Periodic meter calibration. Calibration should be performed at yearly intervals, or as required by law. In general, the Public Utilities Commission requires regulated utilities to periodically calibrate billing meters. Public Works personnel should require copies of calibration records and should have a government representative present during calibration to ensure that standard calibration procedures are followed.

(b) An analog display, or data logging capabilities should be required on utility meters to provide for Navy verification of utility meter readings.

(c) Utilities companies should be required to upgrade meters to the minimum capabilities needed to accurately meter a particular utility. For example, natural gas meters must be pressure compensated.

Section 6. METER TYPES

1. **CATEGORIES OF METERS.** Meters discussed in this manual fall under two categories: those used for electric energy and those that measure fluid flow.

1.1 Electric Meters. The basic meters used in an electric energy management program are:

- Kilowatthour Meter: Measures the total power consumed.

- Demand Meter: This meter, usually part of a kilowatthour meter, measures the average power consumption over specific time periods.

- Power Factor Meter: Power factor meters, located where the main service enters the facility, permit continual monitoring of the power factor for the entire installation. The data contribute to computing consumer billing.

- Power Survey Recorders and Analyzers: Typically monitor and record several parameters such as load power, real power, reactive power, apparent power, power factor, and voltage and current for single-, two-, and three-phase circuits.

- Ammeters: Used to measure current flow to identify and isolate system or equipment energy losses.

1.2 Steam, Water, and Gas Meters. Steam, water, and gas flowmeters can be categorized by principle of operation, which yields the classifications below. Table 2-1 is a compilation of important parameters for these types of meters.

- Differential Pressure Meters: These are the most common type meters in use and include orifice, venturi, flow nozzle, and pitot tube. Used to measure the difference in pressure between two points in the system.

- Positive Displacement Meters: Oscillating piston and nutating disk meters are most often used in the measurement of potable water. Diaphragm meters are used in the measurement of natural gas.

- Velocity Meters: Turbine, vortex shedding, electromagnetic, and sonic design type meters have widespread application.

- Open Charnel Meters: This type of meter is used almost exclusively to measure waterflow in open conduits where a full flow is not required. Characteristically, three sides of the flow are bound by some type of wall with the remaining side being a free surface. Typical open conduits include tunnels, nonpressurized sewers, partially filled pipes, canals, streams, and rivers. Meters of this type are weirs and flumes.

CHAPTER 3. CONCEPTS OF METERING FLUID FLOW

1. **INTRODUCTION.** Selection of the proper meter for measuring a flowing fluid (gas, steam, or liquid) is often a complicated process. Knowledge of certain fluid flow fundamentals will help in understanding the operating principles of various meters and assist in meter selection.

2. **COMPRESSIBLE AND INCOMPRESSIBLE FLOWS.** Flows in which variations in density are negligible are termed incompressible. Density of an incompressible fluid is not affected by changes in pressure and velocity. Flow rates of a compressible fluid are significantly affected by pressure and temperature changes. These characteristics must be considered when measuring the flow of fluids.

3. **MEASURING FLUID FLOW.** With most fluid flow measurement instruments, the flow rate is determined inferentially by measuring the fluid's velocity or change in kinetic energy. Velocity depends on the pressure differential that is forcing the fluid through the pipe or conduit. Because the pipe's cross-sectional area is constant, the average velocity is an indication of flow rate. The basic relationship for determining the fluid's flow rate in such cases is:

$$Q = V \times A$$

where:
Q = flow rate
V = average fluid velocity
A = cross-sectional area of pipe

The equation can be adjusted to determine volumetric, mass, and heat flow rates. For compressible fluids, pressure and/or temperature must be measured to determine the fluid density. This changing density must be used in the basic formula to determine a compensated flow rate.

3.1 Direct Measurement. Direct measurement of fluid flows are made using positive displacement meters. These units cannot meter steam or other high temperature gases. The flowing fluid is divided into specific measurable units and totalized using mechanical or electronic counters.

3.2 Indirect Measurement. Differential pressure and velocity flowmeters indirectly measure fluid flow rates. Many meters in use today operate on the differential pressure concept. Such meters use the correlation between pressure and velocity to determine the rate of flow. This correlation is expressed by the differential pressure formula which states that flow is proportional to the square root of the differential pressure, i.e., $Q \propto (dp)^{1/2}$. For velocity meters the relationship of the continuity equation, $Q = V \times A$, is applied. Velocity meters measure velocity at a point or full bore and calculate flow. A correction factor must be applied to these meters which results in accuracies of 95 to 99 percent.

3.3 Turndown Ratio. Turndown ratio, also known as rangability, is the ratio of the maximum flow rate a meter can accurately measure to the minimum flow that it can accurately measure.

3.4 viscosity. Viscosity, which influences meter selection, may be defined as the ease with which a fluid flows when it is acted upon by an external force. For example, water flows *more* rapidly from a container than heavy fuel oil. Under this condition, water is said to have a lower viscosity than fuel oil. An analogy for gases is somewhat more difficult to visualize, but it is sufficient to know that the viscosity of gases is extremely small compared *to* liquids. When a fluid flows through pipes, viscosity manifests itself as pressure losses and distortion of the velocity profile.

4. **REYNOLDS NUMBER.** The Reynolds Number describes whether a flow will be laminar or turbulent. The Reynolds Number is the ratio of inertia forces to viscous forces. This dimensionless ratio is expressed as:

$$R = \frac{\rho V D}{\mu}$$

where:
R = Reynolds number
P = fluid density
V = average pipeline velocity
D = inside pipe diameter
μ = fluid viscosity

Fluid viscosity and specific gravity are obtained from reference tables. Such tables are available from many sources. Engineering handbooks and manufacturer's data are the most convenient sources.

4.1 Laminar and Turbulent Flow. The difference between a laminar and turbulent flow is shown in Figure 3-1. Laminar flow is described as a smooth flowing liquid. It flows in concentric layers around the center of the stream. The velocity is highest at the center and decreases to the outer edge of pipes. Laminar flow exists when the Reynolds number is approximately 2,000 or less. In applications with low velocity fluid flows or high viscosity media, the flow is usually laminar. If the Reynolds number is greater than approximately 3,000, the flow is assumed to be turbulent. Turbulent flow as contrasted with laminar flow consists of a large number of erratic eddy currents as shown in Figure 3-1. This results in a more uniform velocity profile from the center of the flow to the pipe than is found in a laminar flow; however, if the meter is not designed for this type of flow, its accuracy may suffer. Most applications involve Reynolds numbers above 3,000 due to either high velocity or low viscosity of the fluid. When flowing fluids have a Reynolds number between approximately 2,000 to 3,000, the flow type is unpredictable. This is known as the transition range and flow range may be either laminar, turbulent, or a combination. It should be recognized that the point where the flow characteristics change is an approximate number

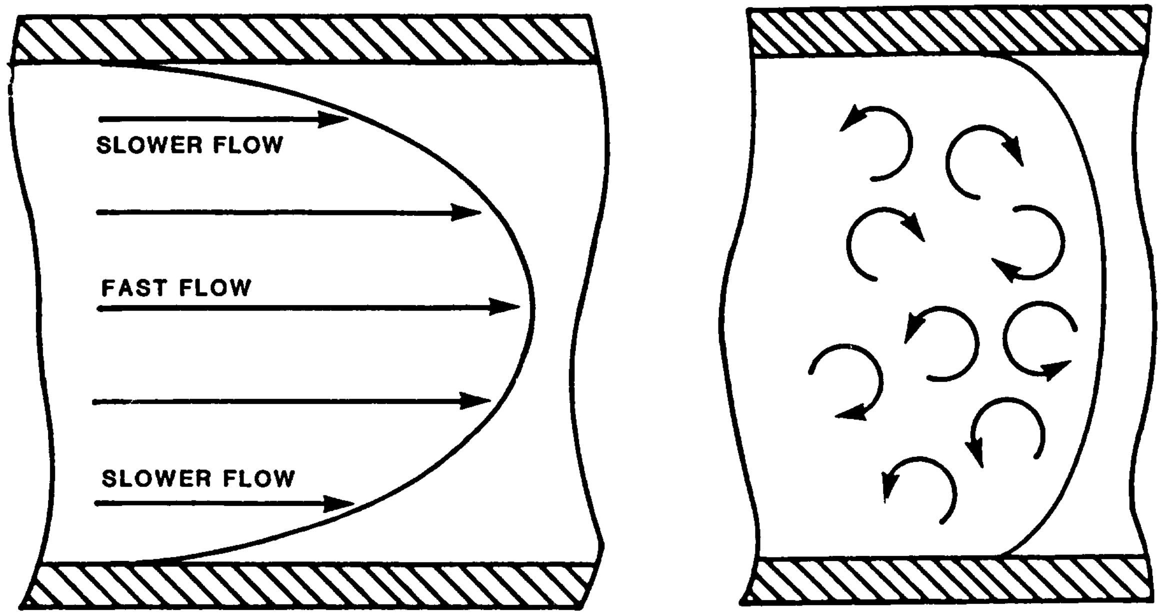


FIGURE 3-1. Laminar and Turbulent Flow Patterns

and the boundary values can vary significantly. The Reynolds number is important because of the impact it may have on final meter selection.

4.2 Nonstable Flow. A nonstable flow can be defined as a fluid that is swirling, pulsating, or changed in character by some projection into the fluid flow or a change in pipe direction. Most meters are designed to tolerate small amounts of nonstable flow and still register an accurate reading. To ensure the highest accuracy, all meters specify varying lengths of straight pipe before and after the meter. These lengths are usually expressed in multiples of pipe diameters. The required length of straight pipe is found by multiplying the pipe diameter by the multiple listed. Under some circumstances, it may not be possible to install meters with the recommended lengths of straight piping before and after the meters. If so, the flow distortions may exceed the ability of the meter to absorb and still return a reading with the required accuracy. If the velocity profile has been so distorted or swirl induced to such a degree that meter accuracy is compromised) installation of flow straighteners in the pipe run q ay correct the situation. Figure 3-2 shows cross-sections of two devices used to straighten fluid flows. Figure 3-2(a) is a section of pipe that is filled with straight tubes which will correct most types of distortions. Figure 3-2(b) is a similar device except that instead of tubes, a grid device assembled at 90 degree angles is inserted into the pipe. Some meters may also

incorporate a short straightening device in the entrance section of the meter. Such meters usually have from 4 to 8 evenly spaced radial vanes just before the meter itself.

4.3 Effect on Installation. Since flow profiles in a pipe are not constant, meters must be correctly positioned during installation. Positioning is specific for each meter and is available from the meter manufacturer.

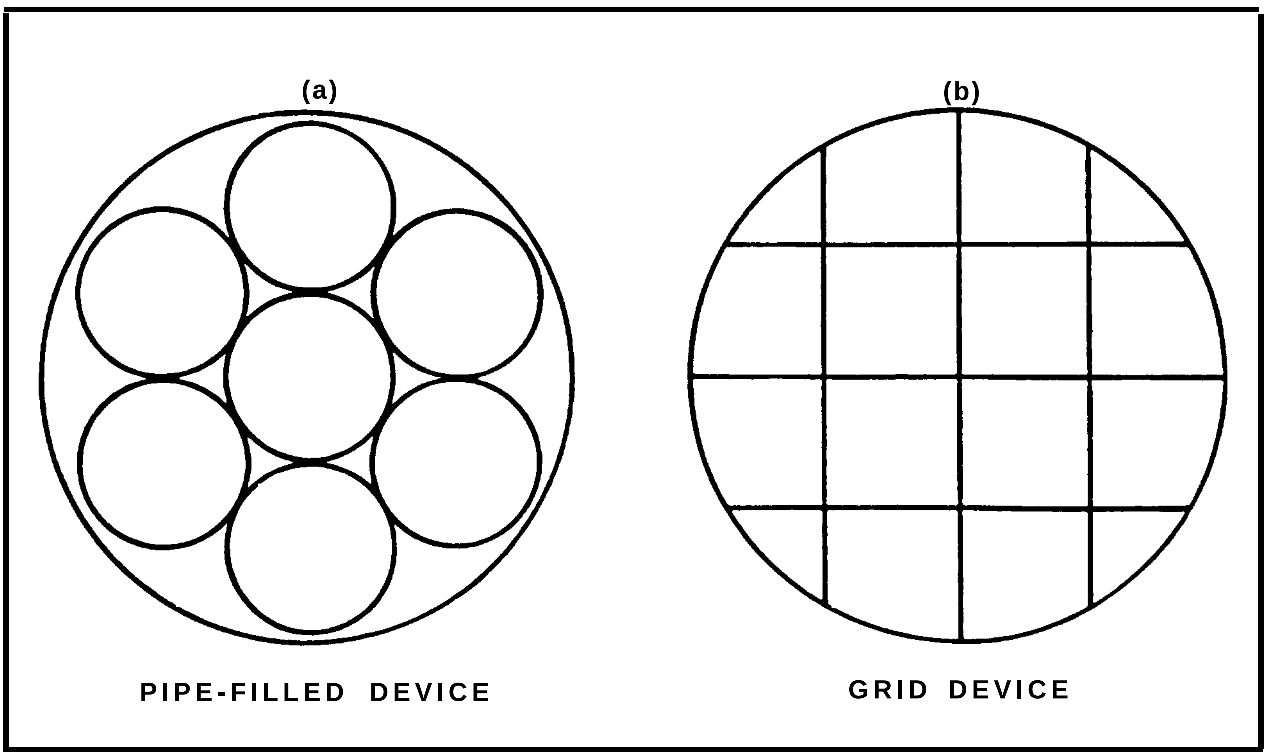


FIGURE 3-2. Cross-Sections of Flow Straightening Devices

CHAPTER 4. POSITIVE DISPLACEMENT AND COMPOUND METERS

Section 10 OSCILLATING PISTON AND NUTATING DISK METERS

1. **INTRODUCTION.** Oscillating piston and nutating disk are the most common type meters used for residential water service. They are essentially equal in performance and have an excellent combination of accuracy, long life, simple design, moderate cost, and ease of maintenance.

1.1 Oscillating Piston Meters.

1.1.1 Meter Design--Oscillating piston meters (Figure 4-1) are available in nominal sizes up to 4 inches, with a maximum capacity of 500 gallons per minute. The operating and physical characteristics of these meters are listed in tables 4-1 and 4-2. This type of meter is commonly used for measuring cold water, but models are available for use with fuel oils and liquified petroleum gas (LPG).

1.1.2 Operating Principles--The main components of an oscillating piston meter are maincase, measuring chamber, and register. As liquid flows through the meter strainer and into the measuring chamber (Figure 4-2) it drives the piston. The piston oscillates around a central hub, guided by the division plate. The motion of the oscillating piston is transferred to a magnetic assembly in the measuring chamber, which drives a follower magnet. The follower magnet drives the register geartrain, which translates the number of piston oscillations into units of total volume that are displayed on the register dial. The unit of measurement must be specified as either gallons, liters, cubic feet, or cubic meters.

1.2 Nutating Disk Meters.

1.2.1 Meter Design-Nutating disk meters (Figure 4-3) are available in nominal sizes up to 6 inches, with a maximum capacity of 1,000 gallons per minute. The operating and physical characteristics of these meters are listed in tables 4-1 and 4-2. This type of meter is commonly used for q easuring cold water, as well as chemical additives and mixture ingredients,

1.2.2 Operating Principles--The basic components of a nutating disk meter are maincase, measuring chamber, and register (Figure 4-3). As liquid flows through the meter strainer and into the measuring chamber it drives the disk (Figure 4-4). Movement of the liquid around the measuring chamber, first above and then below the disk, imparts a nutating motion to the disk (nodding in a circular path without revolving about its own axis). A shaft that is perpendicular to the disk extends from the top of the central ball of the disk. As the disk nutates, the top of the shaft moves in a circular path and, by engaging a crank, operates the meter register. The unit of measurement must be specified as either gallons, liters, cubic feet, or cubic meters.

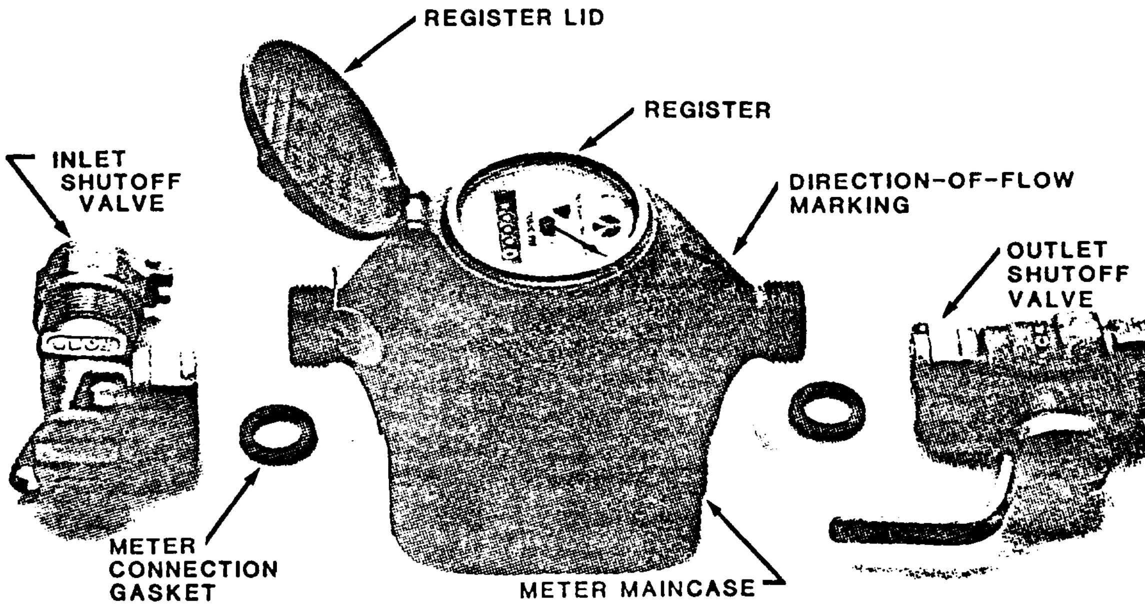


FIGURE 4-1. Oscillating Piston Meter With Inlet and Outlet Valves

2. LIMITATIONS. Rated maximum capacity for oscillating piston and nutating disk meters is shown in Table 4-1. Normal flow for these meters should not exceed approximately one-half of maximum capacity. Operating at maximum capacity-should be limited to short periods or peak loads occurring after long intervals. Maximum pressure loss for both types is from 8.5 to 10.0 percent of maximum operating pressure as shown in Table 4-1. Mechanical drive and some magnetic drive meters have two changeable gears in the geartrain. Changing one or both of these gears allows the ratio between the motion of the piston or disk and the register to be calibrated for maximum accuracy of registration. When used for cold water service, the turndown ratio for these ❑eters is approximately 80:1, depending upon manufacturer, model, and size. Other limitations are as follows:

- Temperature limit is 80°F.
- Pressure limit is 150 psig.
- Installation is permanent.

TABLE 4-1. Operating Characteristics Oscillating Piston and Nutating Disk Meters

Meter size (inches)	Safe Maximum Operating capacity (gpm)	Maximum Pressure Lose at Safe Maximum Operating capacity (psi)	Recommended* Maximum Rate for Continuous (gpm)	Minimum Test Flow (gpm)	Normal Test Flow Limits (gpm)	Maximum Number of Disc Nutations or Piston oscillations	
						Per 10 Cal	Per Cu Ft
5/8	20	13	10	1/4	1-20	580	435
5/8 x 3/4	20	13	10	1/4	1-20	580	435
3/4	30	13	15	1/2	2-30	333	250
1	50	13	25	3/4	3-50	153	115
1-1/2	100	15	50	1-1/2	3-100	67	50
2	160	15	80	2	8-160	40	30
3	300	15	150	4	16-300	20	15
4	500	15	250	7	28-500	9.3	7
6	1,000	15	500	12	48-1,000	4	3

*See paragraph 2

TABLE 4-2. Physical Characteristics* Oscillating Piston and Nutating Disk Meters

Meter Size	Meter Length		Meter Casing Studs			Coupling Nuts		Coupling Tailpiece	
				Pitch Diameter		Pitch Diameter			
	Threaded Spud Ends	Flanged Ends	Nominal Thread Size	min.	max.	min.	max.	Length	Nominal Thread Size
5/8	7-1/2		3/4	0.978	0.988	0.992	1,002	2-3/8	1/2
5/8 x 3/4	7-1/2		1	1.227	1.237	1.242	1.252	2-1/2	3/4
3/4	9		1	1.227	1.237	1.242	1.252	2-1/2	314
1	10-3/4		1-1/4	1.563	1.573	1.580	1.590	2-5/8	1
1-1/2	12-5/8	23	1-1/2	1.780	1.822				
2	25-1/4	17	2	2.253	2.296				
3		24							
4		29							
6		36-1/2							

*Inches
Internal threaded studs

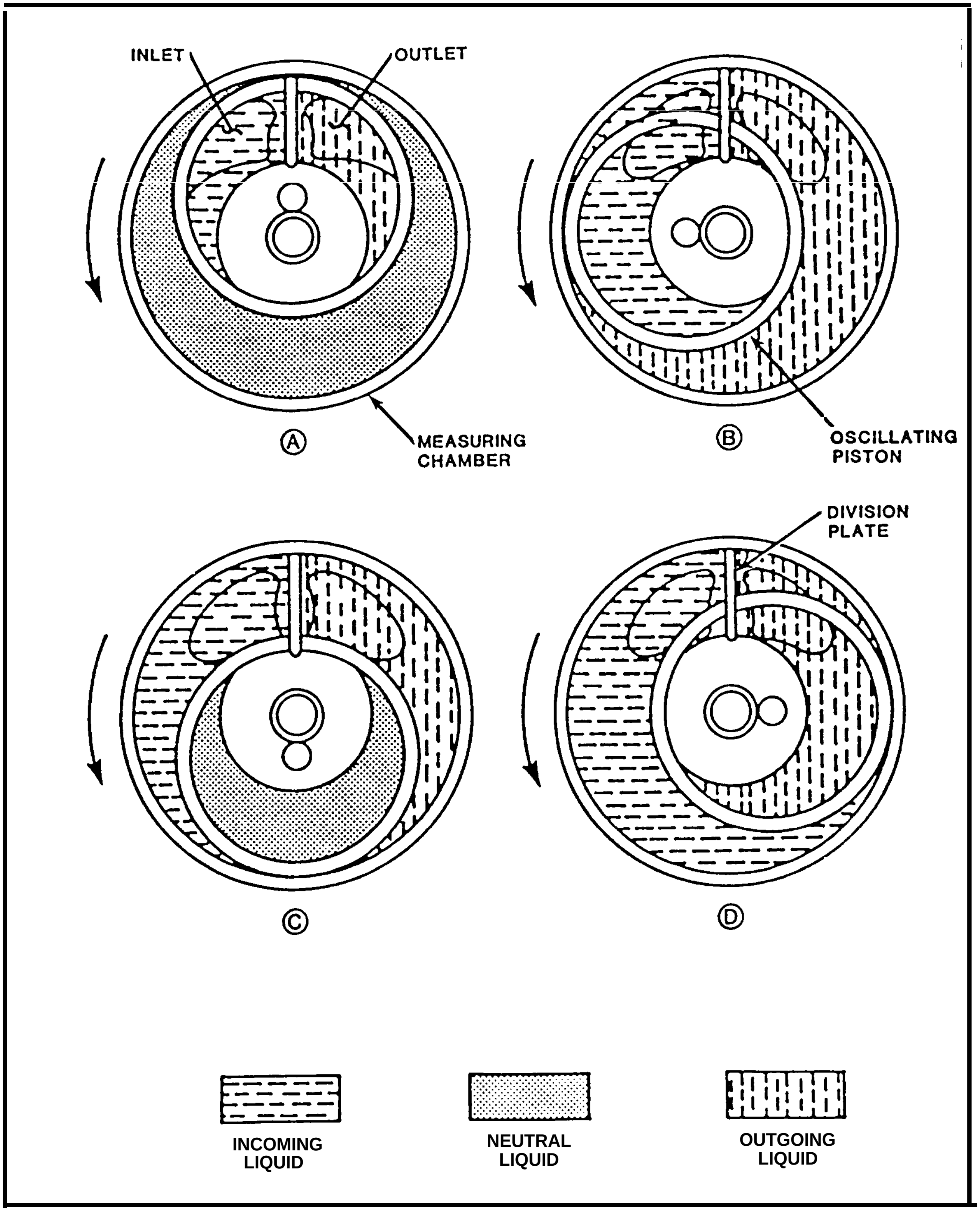


FIGURE 4-2. Operating Cycle, Oscillating Piston Meter

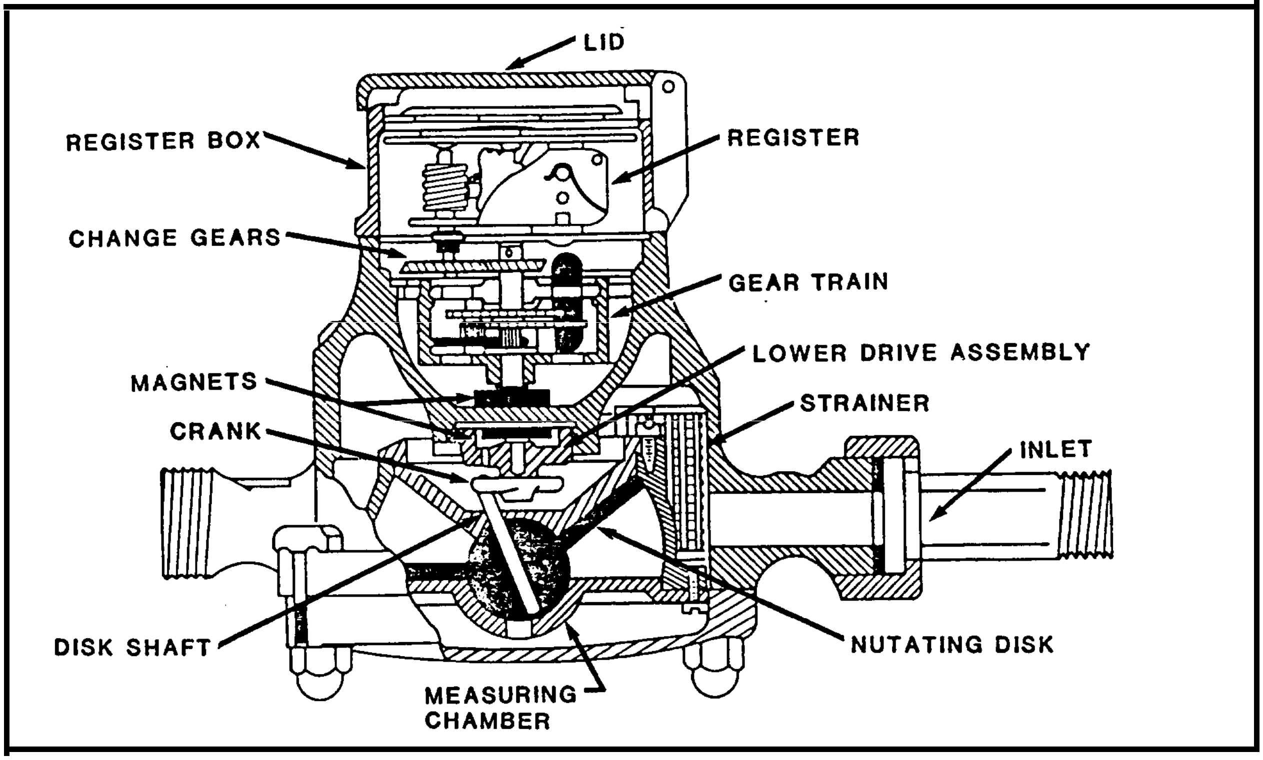


FIGURE 4-3. Magnetic Drive, Nutating Disk Meter

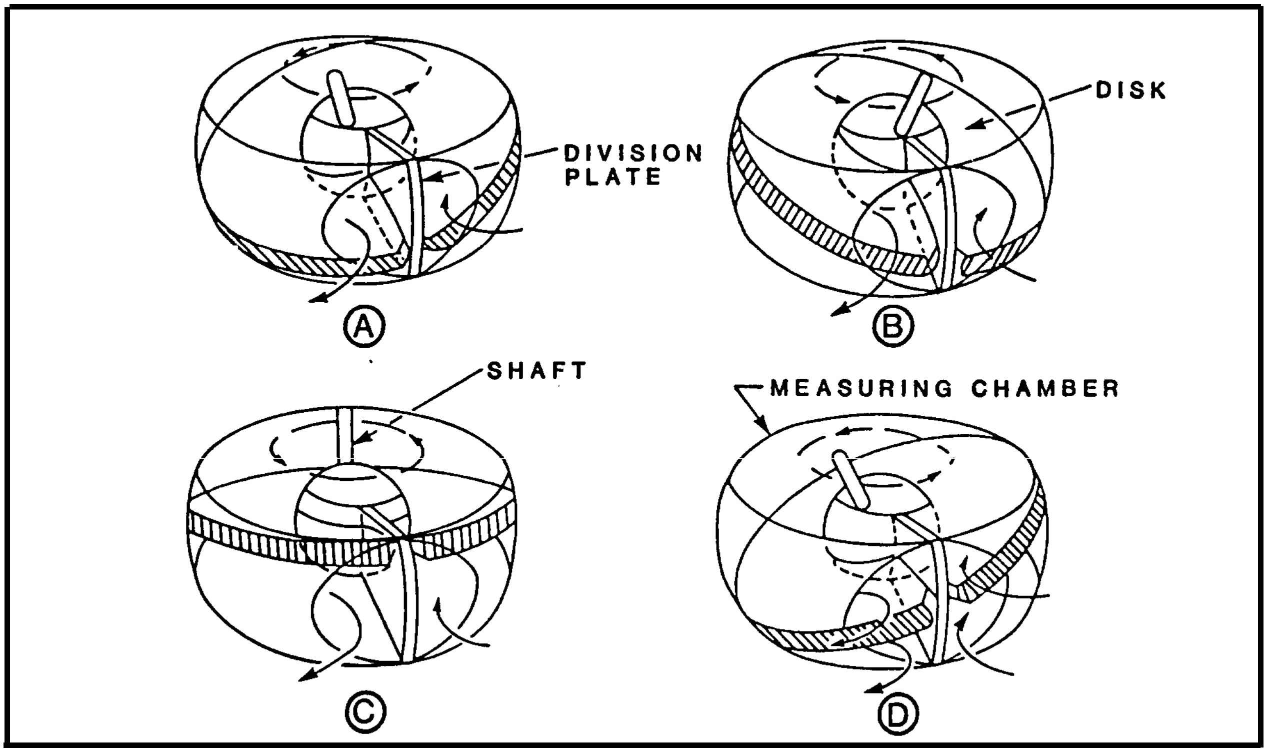


FIGURE 4-40 Operating Cycle, Nutating Disk Meter

3. INSTALLATION. Oscillating piston and nutating disk meters must be installed in the flow line, upstream of the activity or outlet they are monitoring. These meters do not require any minimum length of straight pipe be installed before or after the meter. When installing a meter, be sure the following checks have been made and the indicated items are available.

(a) Check for meter shutoff valve on inlet side of meter.

(b) If extensive line drainage is anticipated, a shutoff valve may be installed on the outlet side of the meter.

(c) Check for adequate supply of meter connection gaskets.

(d) Ensure that location of meter provides protection from frost, traffic, or other hazards that may be present.

(e) Ensure that installation is in accordance with direction-of-flow markings on the meter maincase.

(f) For optimum performance, ensure that meter is positioned in a horizontal plane.

If remote reading or electronic transmitting devices are used, install in accordance with chapter 10 and the manufacturer's instructions.

4. MAINTENANCE. The following inspection schedules are adequate for average installations.

4.1 Monthly Inspection. In addition to any instructions provided by the manufacturer, inspect meters monthly for the following conditions:

(a) Meter is operating.

(b) Noisy operation (repair or replace meter as required).

(c) Leaks (repair as needed).

(d) Cleanliness of glass cover on register dial (clean as needed).

4.2 Annual Inspection. In addition to the inspections in paragraph 4.1, inspect meters annually for the following conditions:

(a) Cleanliness of meter box, housing, or pit (clean as needed).

(b) Adequate protection from freezing (provide protection at least 1 q onth prior to start of the season).

4.3 Periodic Inspection. Periodic inspection of meters is required to determine whether they are measuring accurately. The time between inspections should be based on local conditions and the amount of use. The manufacturer's representative in any particular area should be familiar with local conditions and capable of assisting in the preparation of a schedule for periodic inspection of meters.

5. ACCURACY. Accuracy limits for water meters have been established by industry. For the meters discussed in this section, limits are based on tests run at three different rates of flow; maximum, intermediate, and minimum. The accuracy limits for the maximum and Intermediate rates are from 98.5 to 101.5 percent of the quantity measured. The limits for the minimum rate are from 95 to 101 percent.

Section 2. COMPOUND WATER METERS

1. **INTRODUCTION.** Compound meters are essentially two meters within a single housing. They are normally used in situations that require accurate measurement of cold water over a wide range of low to high flow rates. Compound meters are often used for measuring water used at apartment or office buildings, hotels, schools, hospitals, and industrial facilities.

1.1 Meter Designs. There are two types of compound meter design, parallel and series. The parallel type has two registers and, if either unit fails, the trouble can be detected by stoppage of its register. The series type has only one register. The unit of measurement must be specified as either gallons, liters, cubic feet, or cubic meters. Compound meters are available in nominal sizes of 2 to 10 inches, with a maximum capacity of 2,300 gallons per minute.

2. **OPERATING PRINCIPLES.** The main components of a compound meter are maincase, main line measuring chamber (turbine type), bypass measuring chamber (positive displacement type), compounding valve, and one or two registers. Compound meters operate in two modes; at low flows, only the bypass meter operate, as flow increases, the compounding valve opens, allowing the meter to operate at a higher range. In a parallel meter (Figure 4-5), the main line meter does not operate until the compounding valve opens. The bypass meter may or may not continue operating when the main line meter starts up. In the series meter, when the compounding valve is closed, water flows through the bypass meter. When the pressure differential in the bypass meter is great enough to cause the compounding valve to open, the main line meter is already running. The register is driven by a pair of ratchet drives, so that the unit that is producing q ore registration will drive the register. The main line unit is not called upon to start from rest at the changeover point, and thus loss of accuracy is avoided when the valve opens. Changeover usually begins at approximately 5 or 6 percent of maximum rating of the meter. Operating characteristics for compound meters are listed in Table 4-3.

3. **LIMITATIONS.** Rated maximum capacity for compound meters is shown in Table 4-3. Normal flow for these meters should not exceed approximately one-half of maximum capacity. Operating at maximum capacity should be limited to short periods or peak loads occurring after long intervals. Maximum pressure loss is 13.3 percent of maximum pressure for all sizes. Mechanical drive and some magnetic drive meters have changeable gears in the geartrain. Changing these gears allows the ratio between the motion of the positive displacement or turbine measuring chamber and the register to be calibrated for maximum accuracy of registration. The turndown ratio for these meters

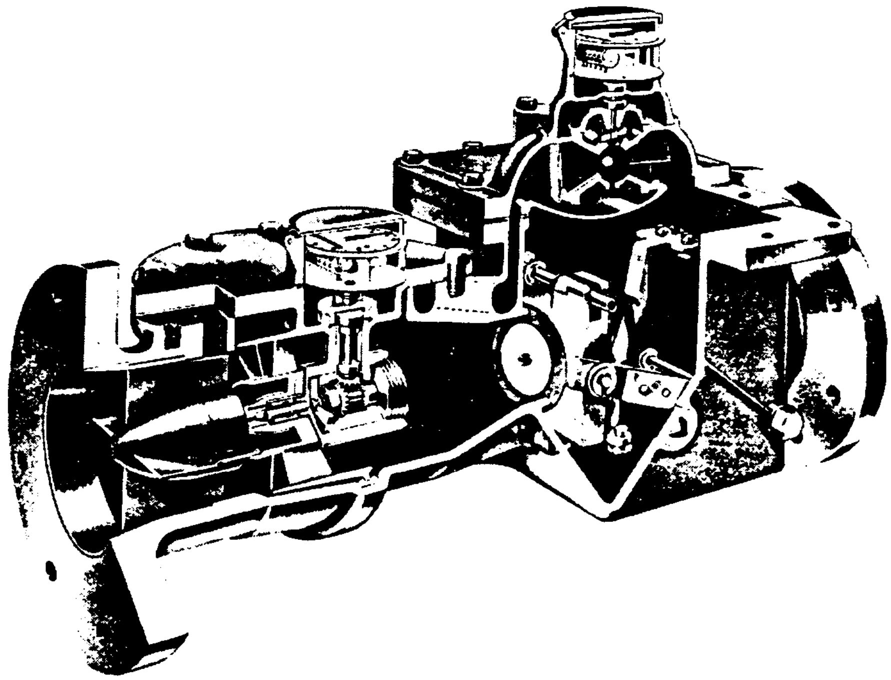


FIGURE 4-5. Double-Register Compound Meter

TABLE 4-3. Compound Meter Operating Characteristics

Meter Size (inches)	Safe Maximum Operating Capacity	Maximum Rate for Continuous Duty (gpm)	Maximum Allowable Loss of Head at Safe Maximum Operating Capacity (psi)	Normal Test Flow Limits (gpm)	Minimum Test Flows (gpm)
2	160	80	20	2-160	1/4
3	320	160	20	4-320	1/2
4	500	250	20	6-500	3/4
6	1,000	500	20	10-1,000	1-1/2
8	1,600	800	20	16-1,600	2
10	2,300	1,150	20	32-2,300	4

when used for cold water service covers a range of approximately 70:1 to 100:1 depending upon manufacturer, model, and size. Other limitations are as follows:

- Temperature limit is 80°F.
- Pressure limit is 150 psig.
- Installation is permanent.

Failure to observe the manufacturer’s recommendations for minimum lengths of straight pipe to be installed, both before and after the meter, may result in inaccurate measurement and premature component wear.

4. INSTALLATION. Compound meters must be installed in the flow line, upstream of the activity or outlet they are monitoring. These meters do require a minimum length of straight pipe be installed before and after the meter. Figure 4-6 shows a typical compound meter installation. When installing a meter, be sure the following checks have been made and the indicated items are available.

(a) Check for meter shutoff valve upstream and downstream of meter.

(b) Check for strainer immediately upstream of meter.

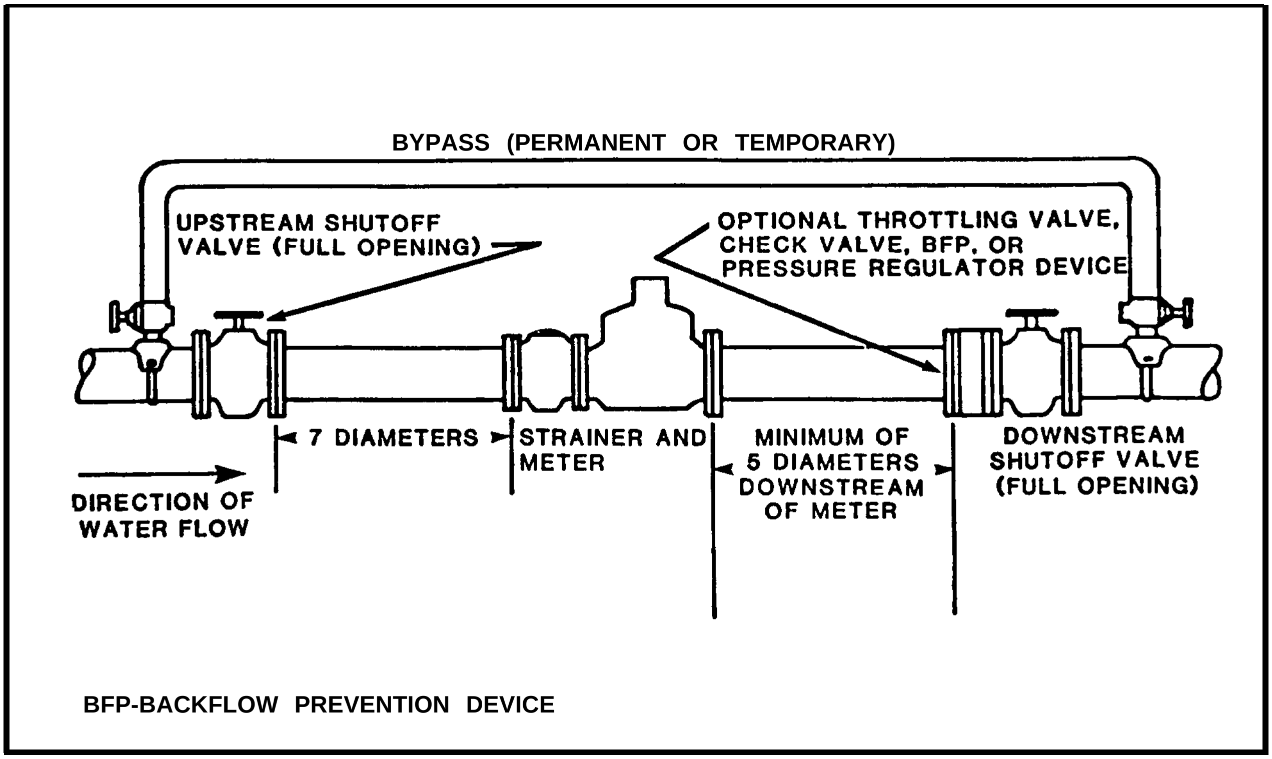


FIGURE 4-6. Typical Compound Meter Installation

(c) Check for adequate supply of meter connection gaskets.

(d) Ensure that location of meter provides protection from frost, traffic, or other hazards that may be present.

(e) Ensure that check valves or pressure-reducing devices are not installed upstream of the meter.

(f) Ensure that check valves and pressure-reducing devices located downstream of the meter are not located closer than 5 pipe diameters.

(g) Ensure that only full-open ball, gate, or plug valves are used immediately upstream of the meter. Butterfly valves are acceptable if they are a minimum of 5 pipe diameters upstream from the meter. Gate or butterfly valves can be used downstream.

(h) Ensure that installation is in accordance with direction-of-flow markings on the meter maincase.

(i) For optimum performance, ensure that meter is positioned in a horizontal plane.

If remote reading or electronic transmitting devices are used, install in accordance with chapter 10 and the manufacturer's instructions. A bypass pipe with gate valves is recommended so that service will not be interrupted during maintenance.

5. MAINTENANCE. The following inspection schedules are adequate for most installations.

5.1 Monthly Inspection. In addition to any instructions provided by the manufacturer, inspect meters monthly for the following conditions:

(a) Meter is operating.

(b) Noisy operation (repair or replace meter as required).

(c) Leaks (repair as needed).

(d) Cleanliness of glass cover on register dial (clean as needed).

5.2 Annual Inspection. In addition to the inspections in paragraph 5.1, inspect meters annually for the following conditions:

(a) Cleanliness of meter box, housing, or pit (clean as needed).

(b) Adequate protection from freezing (provide protection at least 1 month prior to start of the season).

5.3 Periodic Inspection. Periodic inspection of meters Is required to determine whether they are measuring accurately. The time interval between inspections should be based on local conditions and the amount of use. The manufacturer's representative in any particular area should be familiar with local conditions and capable of assisting in the preparation of a schedule for periodic inspection of meters.

6. ACCURACY . Accuracy limits for water meters have been established by industry. For the meters discussed in this section, limits are based on tests run at four different rates of flow; maximum, intermediate, changeover, and minimum. The accuracy limits for the maximum and intermediate rates are from 97 to 103 percent of the quantity measured. The limits for the changeover rate are from 90 to 103 percent. For the minimum test flow rates shown in Table 4-3, compound meters shall register not less than 95 percent of the actual quantity measured.

Section 3. DIAPHRAGM GAS METERS

1. **INTRODUCTION.** Diaphragm meters are used only for gas metering. The principle elements of a diaphragm meter are flexible partitions or diaphragms of the measuring compartments, valves for controlling and directing the gas flow in filling and emptying the measuring compartments, appropriate linkage to keep the diaphragms and valves synchronized, register for counting the number of cycles, and maincase to house the components. To obtain continuous flow and power to operate the register, it is necessary to have three or more measuring compartments or chambers, with two or more movable walls. These walls are sealed with a flexible material that is impervious to gas. Movement of the walls or diaphragms are so regulated that the total displacement on successive cycles is the same. The amount of travel or stroke of the diaphragms is regulated in most meters by the radial position of the crankpin that the diaphragm linkage arms are attached to. Figure 4-7 shows the sequence for filling and emptying a meter that has two diaphragms and four measuring chambers. The most common unit of measurement for these meters is cubic feet. Diaphragm meters are available to fit pipe sizes up to 4 inches, with a maximum capacity of 12,000 cubic feet per hour.

2. **INSTALLATION.**

CAUTION

Any shock, excess jarring, tipping, or turning upside down of the meter or regulator may cause internal damage, resulting in equipment failure or inaccurate measurement.

Diaphragm meters must be installed in the flow line, upstream of any activity or outlet they are monitoring. Always check manufacturer's instructions prior to installation for the proper methods of handling, storage, transit, and installation. When installing a meter, be sure the following checks have been made and the indicated items are available.

(a) Securely restrain and properly cushion meters during transit to prevent tipping and excess jarring.

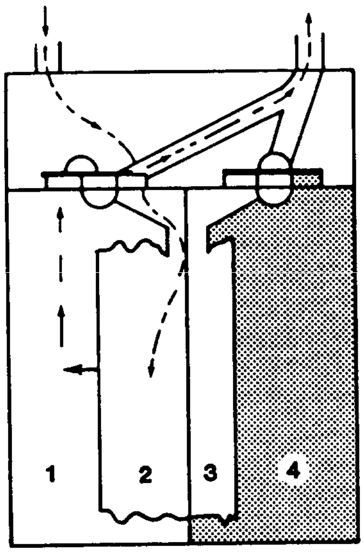
(b) Keep meter hubs covered and protected until ready for installation.

(c) When a separate pressure regulator is required, keep inlet and outlet plugged and protected until ready for installation.

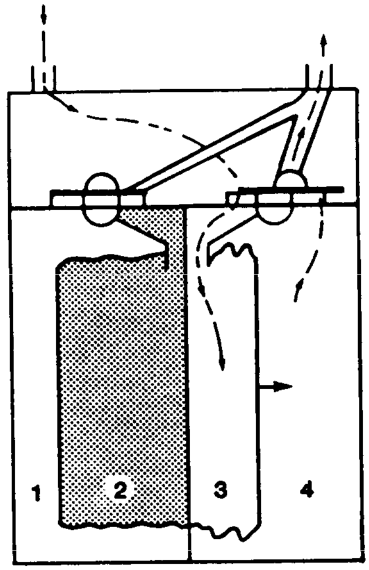
(d) Ensure that the inlet piping is clean and does not contain any pipe scale, chips, rust flakes, or other foreign materials.

CAUTION

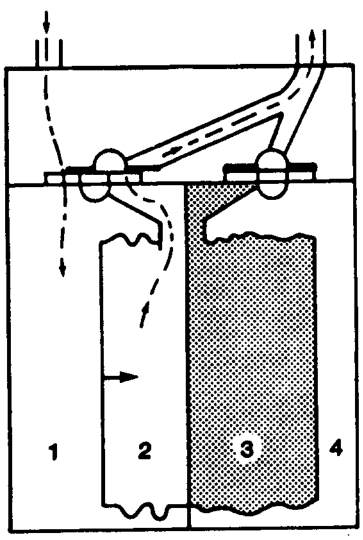
Installing meters in a tilted position may cause inaccurate meter operation and registration.



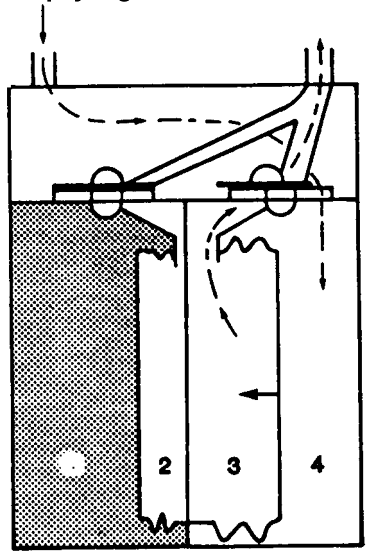
A. Chamber 1 is emptying, 2 is filling, 3 is empty, and 4 is full.



B. Chamber 1 is empty, 2 is full, 3 is filling, and 4 is emptying.



c. Chamber 1 is filling, 2 is emptying, 3 is full, and 4 is empty.



D. Chamber 1 is full, 2 is empty, 3 is emptying, and 4 is filling.

FIGURE 4-7. Operating Cycle, Four-Chamber Diaphragm Meter

(e) Ensure that the meter is installed plumb and level.

(f) Check for meter shutoff valve on inlet side of meter.

(g) Check for adequate supply of meter connection gaskets.

(h) Ensure that location of meter provides proper protection from traffic or other hazards that may be present.

If remote reading or electronic transmitting devices are used, install in accordance with chapter 10 and the manufacturer's instructions.

3. MAINTENANCE. The following inspection schedules are adequate for average installations.

3.1 Monthly Inspection. In addition to any instructions provided by the manufacturer, inspect meters monthly for the following conditions:

(a) Noisy operation of meter.

(b) Smooth movement of register.

(c) Leaks (repair if necessary).

(d) Cleanliness of glass cover on register dial (clean as needed).

3.2 Annual Inspection. In addition to the inspections in paragraph 3.1, inspect meters annually for the following conditions:

(a) Proper alignment and position in accordance with installation instructions.

(b) Cleanliness of meter box, housing, or pit, if one exists (clean as needed)

A schedule for cleaning and repairing meters is necessary, and should be based on the manufacturer's recommendations.

CHAPTER 5. DIFFERENTIAL PRESSURE METERS

Section 1. ORIFICE PLATE METERS

1. **INTRODUCTION.** Orifice plate meters are the most common meter used in industry today. It is estimated that over 50 percent of the devices used for measuring fluids are orifice plate type. The widespread use of orifice plates provides a great deal of background and operational experience in a variety of situations.

1.1 Operating Principles. Orifice plates can be used to measure flow because of the velocity-pressure relationship that exists in a flowing fluid. When a restriction, such as an orifice plate, is inserted into a stream, the fluid velocity must increase when passing through the restriction. The increase in velocity is accompanied by a proportional drop in pressure on the downstream side of the orifice plate (Figure 5-l). Since the pressure drop across the meter is proportional to the square of the flow rate, it is possible to calculate the flow rate by measuring the differential pressure (alp) before and after the orifice. Instruments of this type are known as inferential meters as they do not physically measure the flow, but rather "infer's it from the known relationship between pressure and velocity.

2. **METER DESIGNS.** There are different orifice plate designs such as square-edged, one-quarter circle, and conical. For the q ajority of flow measurements involving gases, air, steam, and water, the square-edged orifice plate is used. Other configurations are primarily designed to address particular situations such as high viscosity, erosive fluids, and fluids containing suspended material.

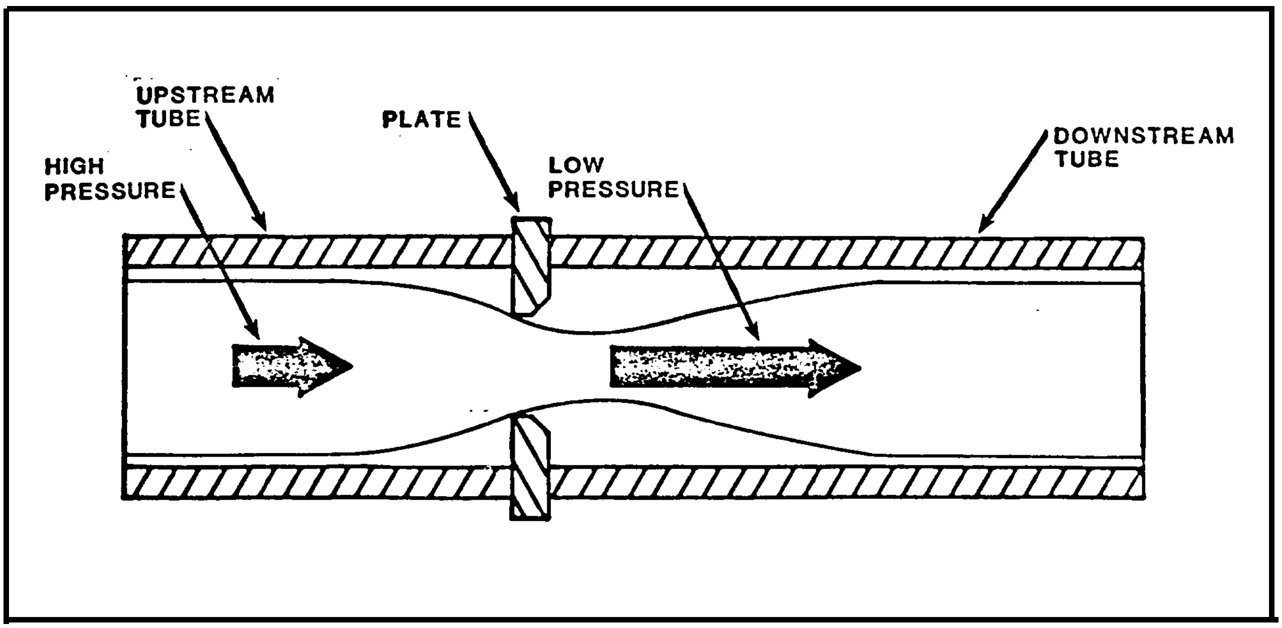


FIGURE 5-1. Typical Orifice Plate Conditions

2.1 Square-Edged Orifice. The orifice is sized to meet one specific anticipated flow rate. The upstream face of the orifice is flat with a square edge where the orifice meets the plate surface (Figure 5-2). If the side with a beveled or recessed edge is facing upstream, erroneous data will result.

2.1.1 Recommended Applications. Square-edged orifice metering is applicable on gas, liquid, and steam flow systems when pipe sizes are greater than 2 inches in diameter.

3. SPECIAL ORIFICES. These orifices are designed for special flow situations. One-quarter circle and conical entrance devices address low-flow and high-viscosity situations. Their use is limited. In an effort to prevent a buildup of debris on the upstream side of an orifice plate, eccentric orifice plates are used where moisture-laden gases are flowing and segmental orifice plates are used where a liquid containing a large percentage of gas is flowing (Figure 5-2).

4. LIMITATIONS. Orifice meters cause some permanent pressure loss due to friction. Pressure loss, increased friction, and increased pumping costs may make orifice metering undesirable. The range of this metering system is limited from 3:1 to 4:1. Turndown ratio can be increased by using two or more dp transmitters of different rangeabilities with an obvious increase in cost. They may be mounted in series and connected to a decision processor that will select the appropriate transmitter dependent upon the differential pressure (alp) . Since transmitters are expensive, the use of multiple transmitters is a tradeoff between precision requirements and cost effectiveness. Other limitations are as follows:

- Temperature range is to l,OOO°F.
- Pressure limit is 6,000 psig.

5. INSTALLATION. The location of the orifice plate in the system is important. Whenever possible, it is preferable to locate the primary element in a horizontal line. For accurate flow measurement, the fluid must enter the primary element with a fully developed velocity profile, free from swirls or vortices. In addition, fluid must exit the bevelled side of the orifice. Such a condition is best achieved by the use of adequate lengths of straight pipe, both preceding and following the primary element. The minimum recommended lengths of piping are shown in Figure 5-3. The diagram in Figure 5-3 that corresponds closest to the actual piping arrangement for the meter location should be used to determine the required lengths of straight pipe on the inlet and outlet. These lengths are those necessary to limit errors due to piping configurations to less than ±%0.5 percent. If these minimum distances are not observed, or if the orifice plate is installed with the bevel on the inlet side, flow equations and resultant flow calculations may produce inaccurate data.

5.1 Meter Installation. Common methods of installing orifice plate meters are described in the following paragraphs.

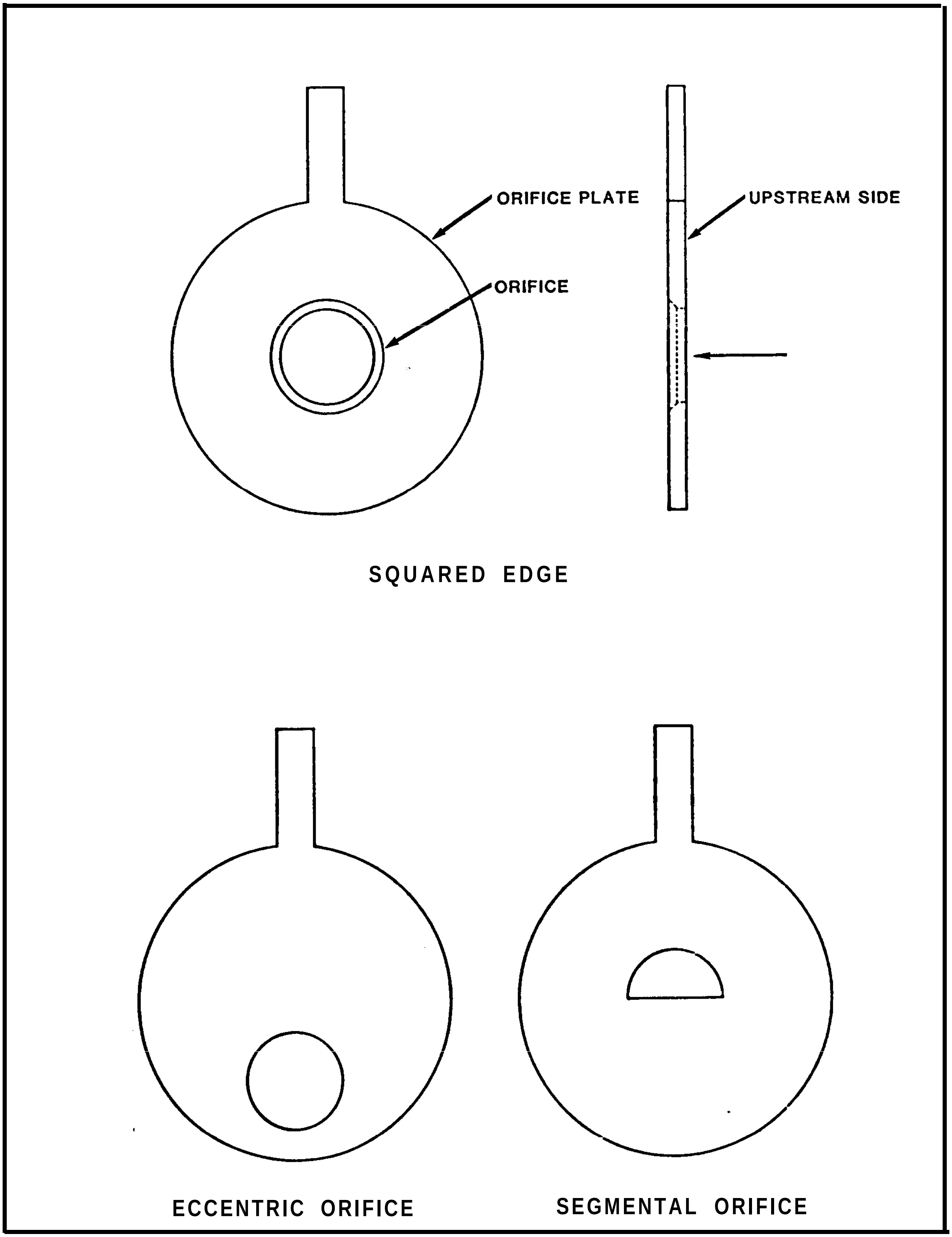
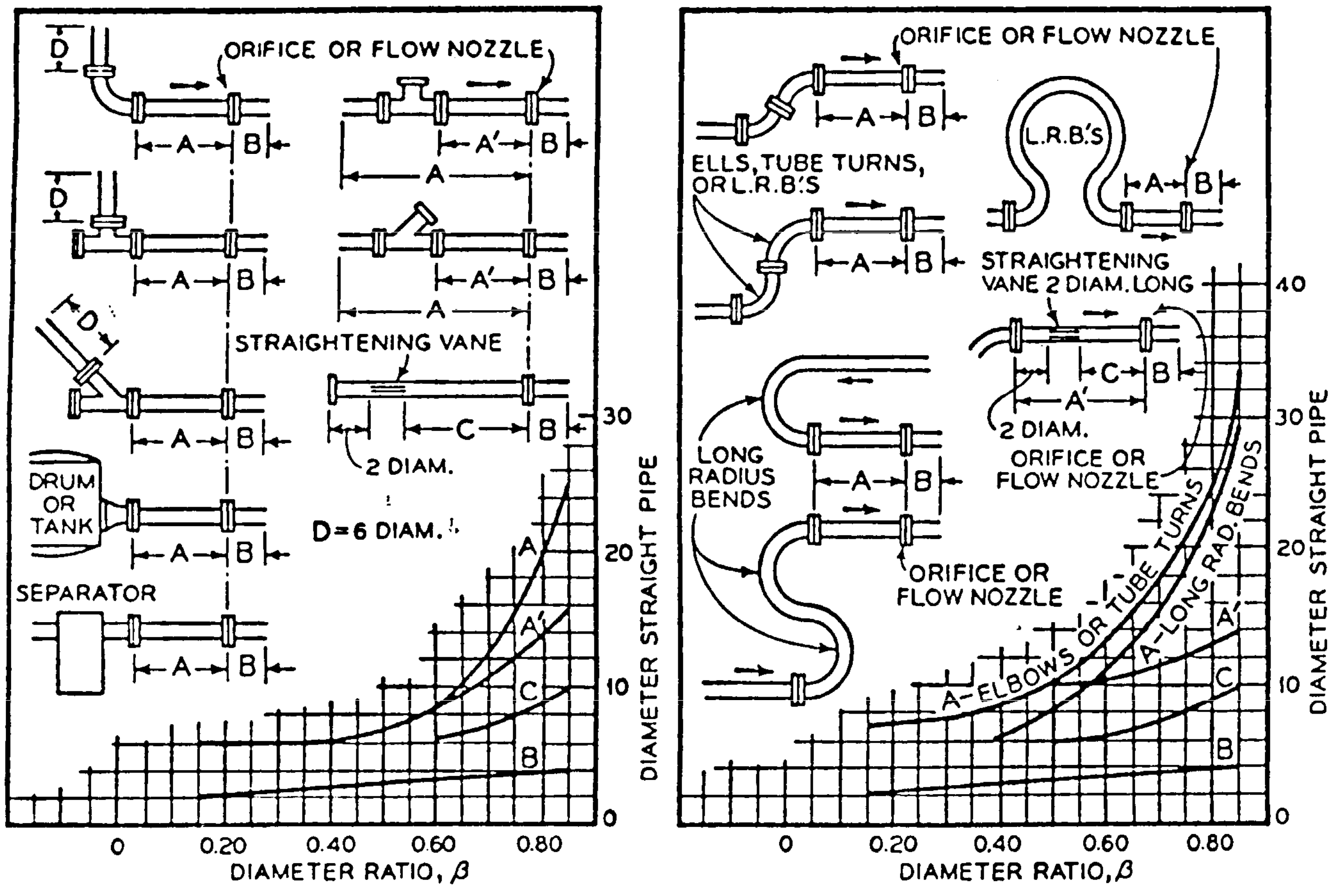


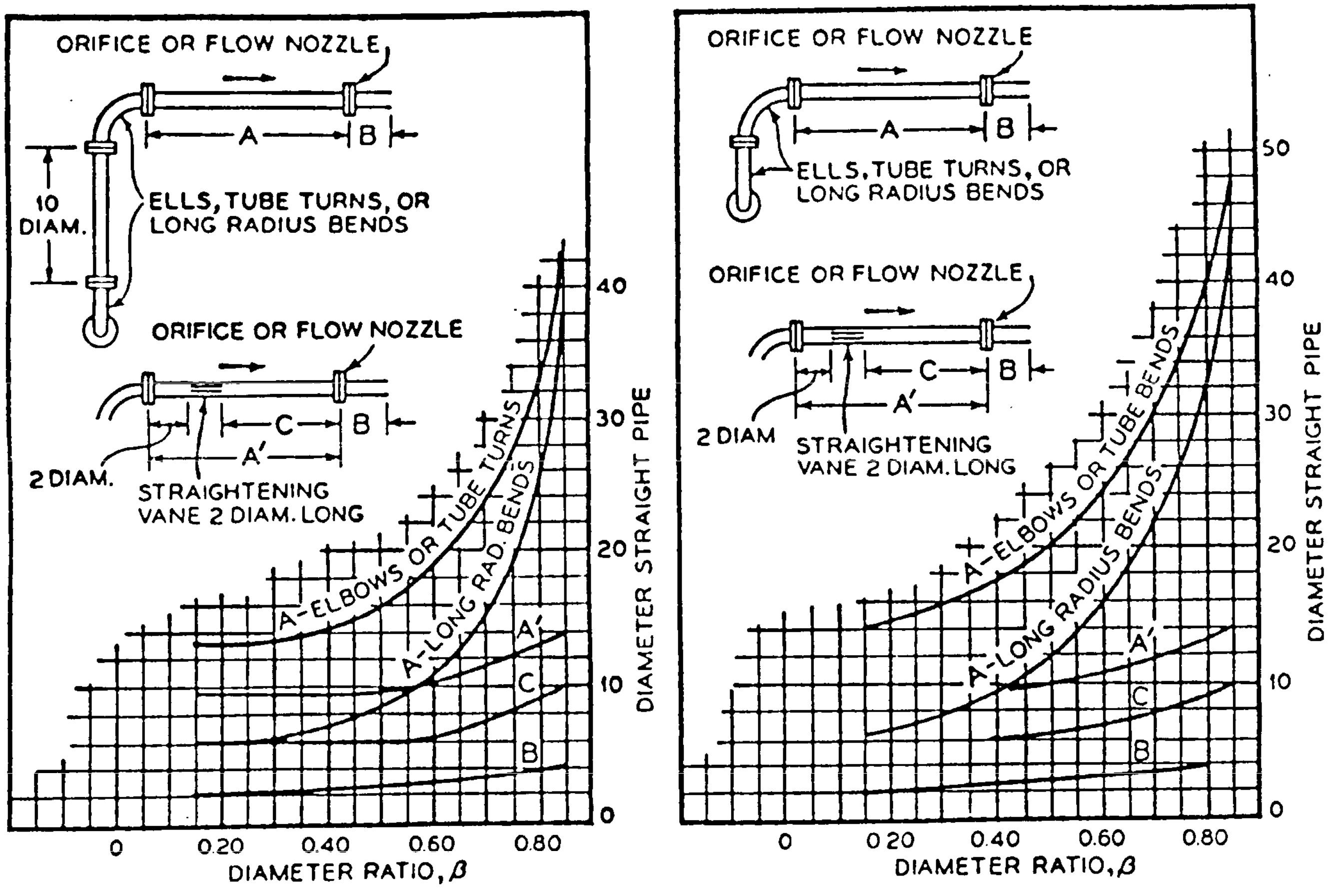
FIGURE 5-2. Orifice Plates



(A) FOR ORIFICES AND FLOW NOZZLES
ALL FITTINGS IN SAME PLANE

(B) FOR ORIFICES AND FLOW NOZZLES
ALL FITTINGS IN SAME PLANE

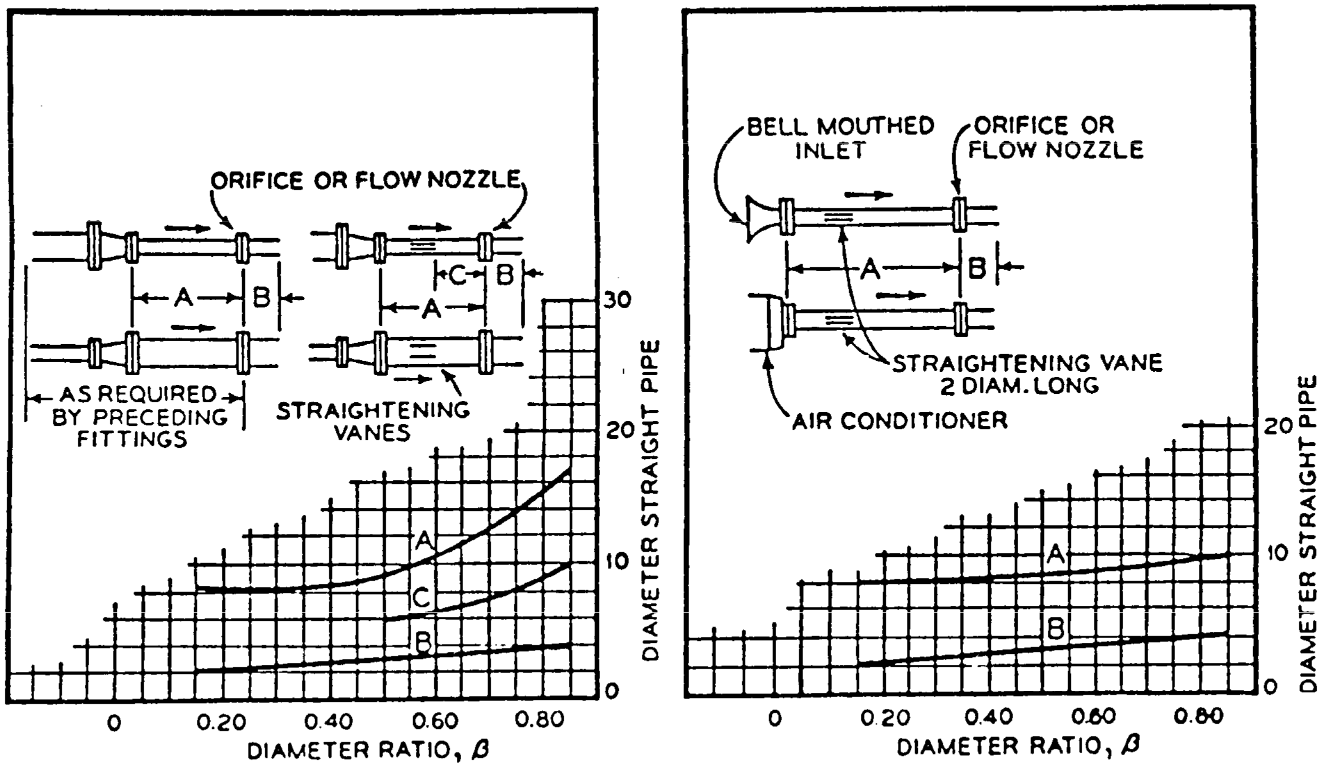
FIGURE 5-3. Recommended Minimum Pipe Lengths
Before and After Differential Pressure Meters
(From ASME Fluid Meters; used with permission) (Page 1 of 4)



(C) FOR ORIFICES AND FLOW NOZZLES FITTINGS IN DIFFERENT PLANES

(D) FOR ORIFICES AND FLOW NOZZLES FITTINGS IN DIFFERENT PLANES

FIGURE 5-3. Recommended Minimum Pipe Lengths Before and After Differential Pressure Meters (From ASME Fluid Meters; used with permission) (Page 2 of 4)



(E) FOR ORIFICES AND FLOW NOZZLES WITH REDUCERS AND EXPANDERS

(F) FOR ORIFICES AND FLOW NOZZLES IN ATMOSPHERIC INTAKE

FIGURE 5-3. Recommended Minimum Pipe Lengths
Before and After Differential Pressure Meters
(From ASME <u>Fluid Meters</u>; used with permission) (Page 3 of 4)

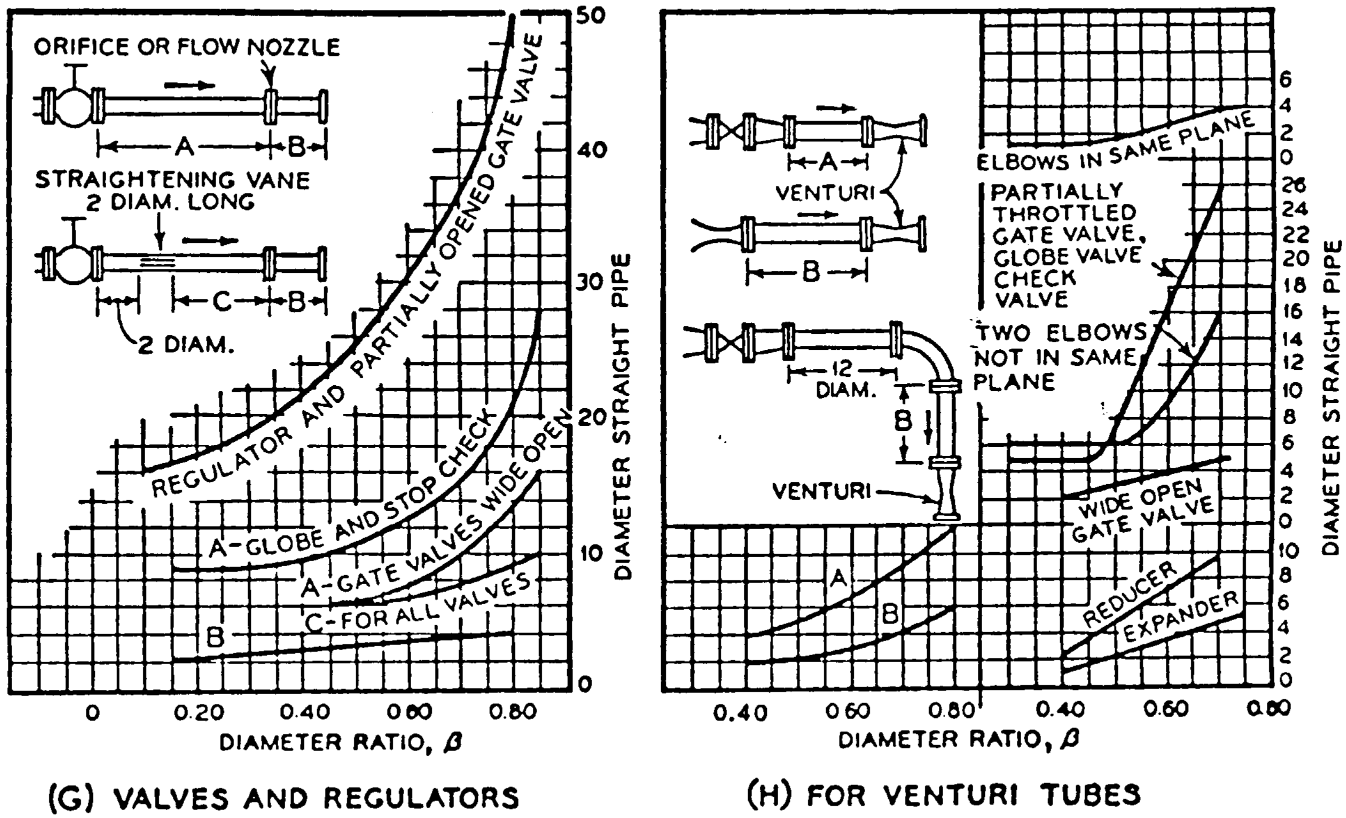


FIGURE 5-3. Recommended Minimum Pipe Lengths
Before and After Differential Pressure Meters
(From ASME Fluid Meters; used with permission) (Page 4 of 4)

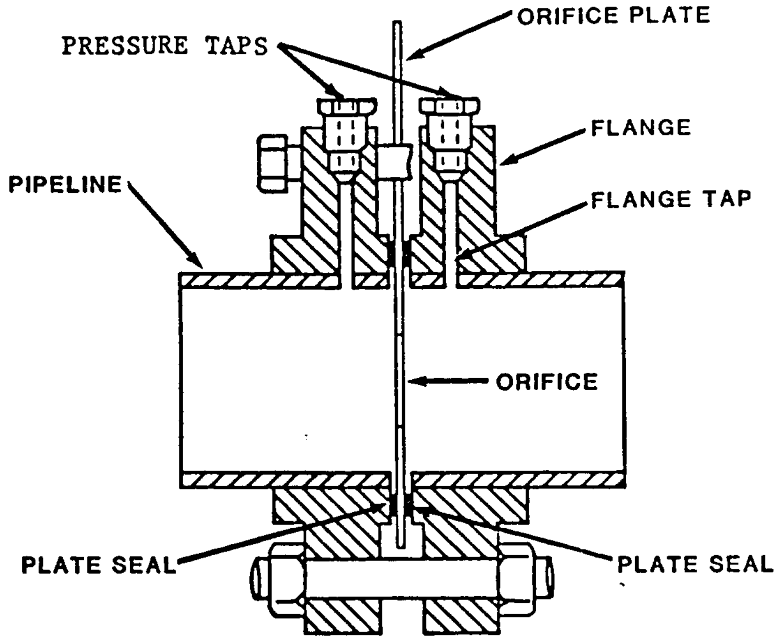


FIGURE 5-4. Orifice Meter With Flange Taps

5.1.1 Orifice Flanges. Special orifice flanges are the most commonly recommended method for meter installation. The pressure taps are drilled into the flanges themselves, which are welded onto the pipe. The orifice is inserted and secured between the two flanges (Figure 5-4).

5.1.2 Carrier Rings. Carrier rings are the second q ost common method of orifice plate installation. Pressure taps, typically corner taps, are drilled into the rings and the orifice plate is inserted between the rings. The rings and orifice are then inserted between existing pipe flanges (Figure 5-5).

5.1.3 Existing Flanges and Special Taps. The orifice plate can be inserted between existing pipe flanges and pressure taps drilled into the pipe. This method was widely used in the past, but has since been replaced with the more standardized orifice flanges (paragraph 5.1.1).

6. PREFABRICATED METER ASSEMBLIES

6.1 Insertion Fittings. Some manufacturers produce a dual-chambered, hand-operated, gear-driven apparatus which allows one person to change an orifice plate. An insertable plate can be changed without system shutdown or removal of flanges. The mechanism is constructed so that there is no fluid spillage or loss and no danger to the operator. For specific product information consult manufacturers of fluid flow metering equipment.

6.2 Recommended Applications. Prefabricated meter assemblies are Particularly suited for low flow in pipes of less than 2 inches in diameter" A common application is for measuring natural gas flow to specific pieces of equipment.

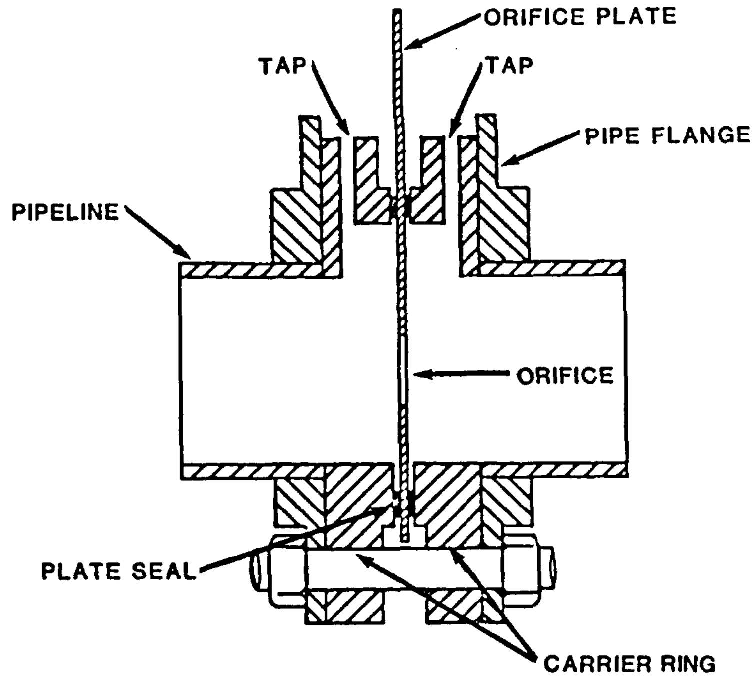


FIGURE 5-5. Orifice Meter With Corner Taps

6.3 Limitations. Prefabricated orifice meter assemblies cannot measure over an infinite range. The turndown of an orifice meter is 3:1 and, therefore, predetermined orifice sizing is required to obtain accurate measurement data.

6.4 Installation. Prefabricated meter assemblies are permanently installed meters fitted in a specially designed length of pipe with permanently located pressure taps. The complete assembly is installed in the pipe where flow is to be measured. The prefabricated assembly is sized for a particular flow range and is calibrated accordingly.

7. **MAINTENANCE.** The following procedures are the minimum required for the most common types of units. When developing q aintenance schedules, refer to the manufacturer's instructions. Annually disassemble meter and inspect and perform maintenance as follows:

(a) Check orifice for wear, i.e., roundness, size, and squareness of edge.

(b) Plate should be examined for warping with a straightedge.

(c) Plate should be examined for watermarks indicating condensate damming.

(d) Check pressure taps for burrs and/or debris.

(e) Test dp transmitter with dead weight pressure tester and rescale if necessary.

(f) Dress off roughness on plate.

(g) Resize orifice, if necessary, based on flow of previous year. When orifice is resized, stamp the new diameter and coefficient on the holder.

(h) Flush all trapped sediment from unit.

(i) Reinstall orifice plate so that flow exits the bevelled side.

(j) Sensor lines should be blown down at regular intervals.

Since inspection of an orifice plate requires shutdown, scheduling may be predicated by system supply requirements.

8. ACCURACY AND RELIABILITY. Orifice meter accuracy is up to ±%0.75 percent of full scale. The major influence on accuracy is installation, where care must be taken to ensure proper installation of the run, pressure taps, and the tap tubing. Meter runs are highly reliable when used over the range of calibration. If removed for cleaning or inspection, they should be recalibrated before returning to service.

9. PRESSURE TAPS AND INDICATION DEVICES. A variety of pressure tap configurations are available for orifice plates. Various devices are used to quantitatively express the differential pressure. Each of the common tap options and dp devices are described in the following paragraphs.

9.1 Pressure Taps. The common tap options are: flange taps, corner taps, and radius taps.

9.1.1 Flange Taps. The most commonly recommended configuration is the flange tap (Figure 5-4). Pretapped flanges are standardized, convenient, and easily replaced.

9.1.2 Corner Taps. Carrier rings are drilled for pressure taps and insertion between existing flanges (Figure 5-5). This type of flange should only be used if the flange taps are unavailable. Standardization of equipment should be the goal of a well-planned system.

9.1.3 Radius and Vena Contracta Pipe Taps. These taps are mounted directly in the pipe (Figure 5-6). Although widely used in the past, they have been largely replaced with standardized flange taps.

9.2 Differential Pressure Devices. Dp devices are used to provide a quantitative display of the differential pressure; they are also called delta P and ΔP devices. The four most common dp devices are: manometer, diaphragm, bellows, and electronic. All new or replacement differential pressure installations should be electronic.

9.2.1 Manometer. The manometer is a rather simple device. One end of the manometer is attached to the high-pressure tap and the other end to the low-pressure tap of the orifice plate installation. As the dp created by the orifice plate is sensed by the manometer, a column of fluid in the manometer allows the dp to be read directly on a scale (Figure 5-7). Refer to the manufacturer's instructions before installing a manometer.

9.2.2 Diaphragm. The diaphragm device includes a hermetically sealed diaphragm that is in an enclosure with one side open to the high-pressure tap and the other side to the low-pressure tap (Figure 5-8). The diaphragm moves as the dp created by the orifice meter is transmitted to the diaphragm chamber. A pointer attached to the diaphragm pivots about a fulcrum in the wall of the chamber and mechanically indicates the dp directly on a scale. Refer to the manufacturer's instructions before installing a diaphragm.

9.2.3 Bellows. A bellows device is similar to the diaphragm device in that the indicator pointer is attached to a component that is subject to q ovement caused by the dp. In a bellows device, a partition is hermetically sealed between two bellows in a confined compartment with an opening on one side to the high-pressure tap and another to the low-pressure tap (Figure 5-9). The input ends of the bellows are fixed to the compartment walls. As the dp forces the partition to move, compressing and expanding the respective bellows, a lever system causes a pointer to directly indicate the dp on a scale. Refer to the manufacturer's instructions before installing a bellows.

9.2.4 Electronic. Electronic devices are also known as capacitance devices. In an electronic device, the dp is transmitted through an isolating diaphragm to a hermetically sealed sensing diaphragm in the center of the device (Figure 5-10). The sensing diaphragm is surrounded by silicone oil contained between capacitors. As the sensing diaphragm deflects in proportion to the dp, the position of the diaphragm is detected by capacitor plates on each side of the diaphragm. The differential capacitance between the plates and the diaphragm is converted electronically to a 2-wire, 4-20 mA, or 0-10 volt data transmission signal. Electronic devices are available in both square root and linear function models. Solid state, plug-in components simplify maintenance/repairs.

9.2.5 Calibration. Static calibration should be performed on all dp devices at least every 6 months.

9.3 Data Transmission. Readings from various dp devices must often be transmitted to remote data collection and recording sites. his is because the dp device may be too remote to warrant onsite reading. Data transmission may also be necessary because there may be many widely dispersed devices to be read and it would be uneconomical to have each one read onsite; or a central data management point has been set up to collect, record, plot, reduce, and analyze all flow data. All the taps for dp will accommodate remote transmission fittings along with the various dp devices.

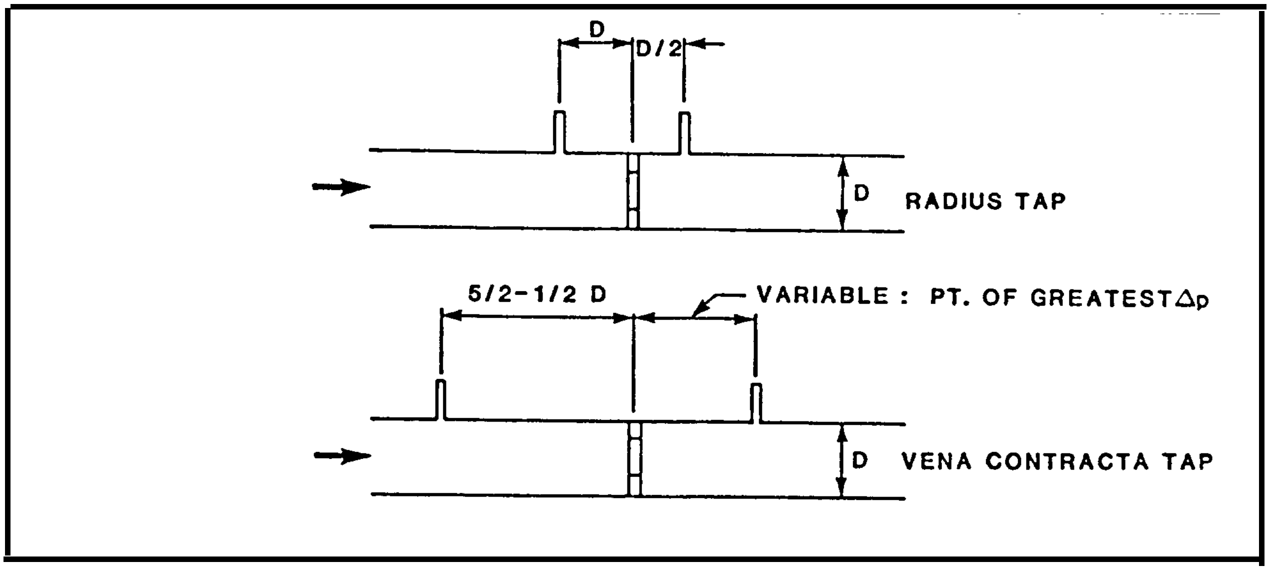


FIGURE 5-6. Orifice Meter With Radius and Vena Contracta Pipe Taps

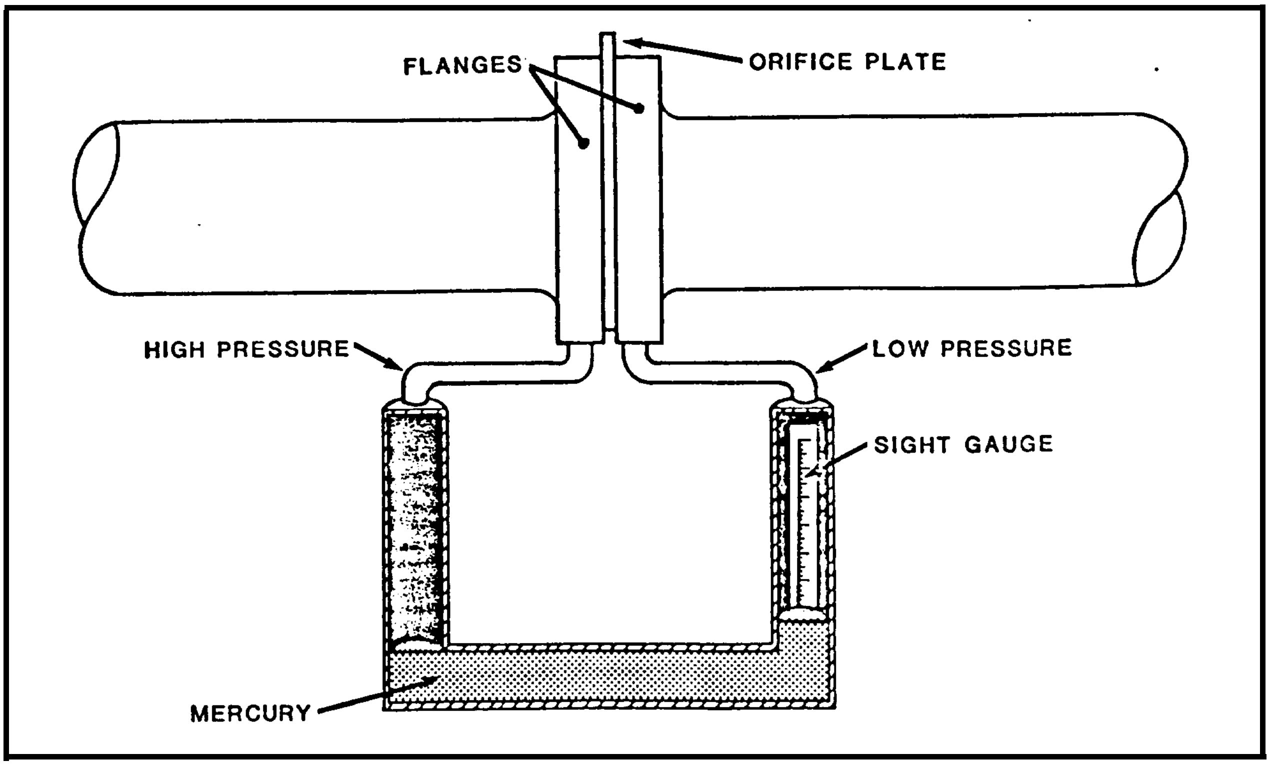


FIGURE 5-7. Manometer

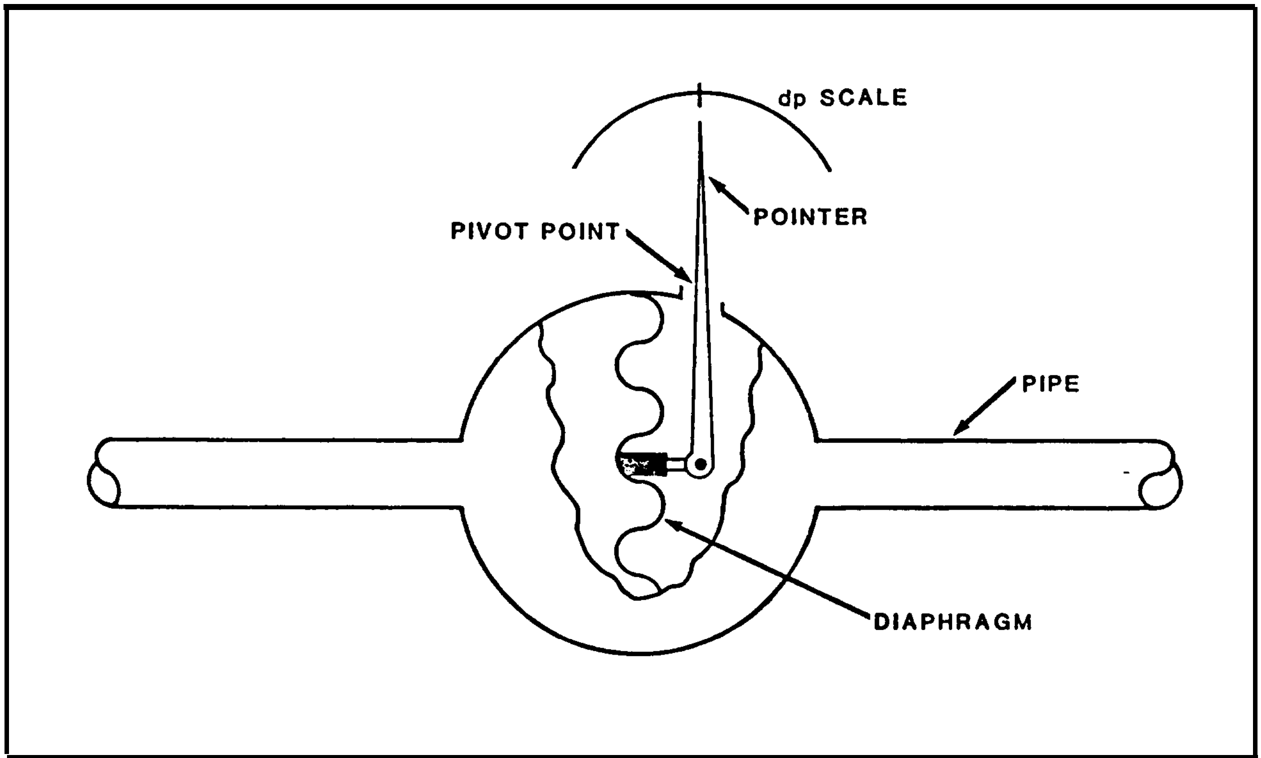


FIGURE 5-8. Diaphragm

9.3.1 Pneumatic. All dp devices, except electronic, can have readings transmitted to a remote site by pneumatic lines.

9.3.2 Electrical. Rather than pneumatically, the recommended means of data transmission is to have the dp electronically converted to an analog signal and transmitted electrically to a data collection center.

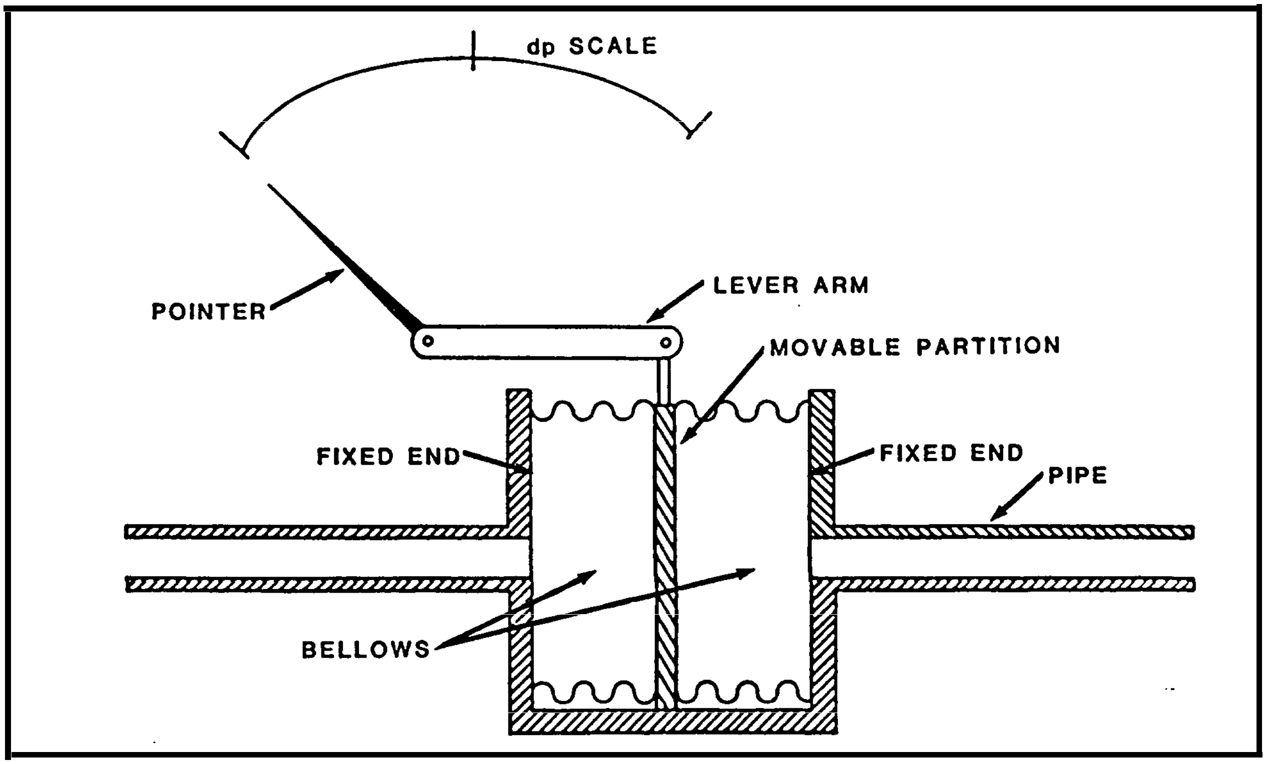


FIGURE 5-9. Bellows

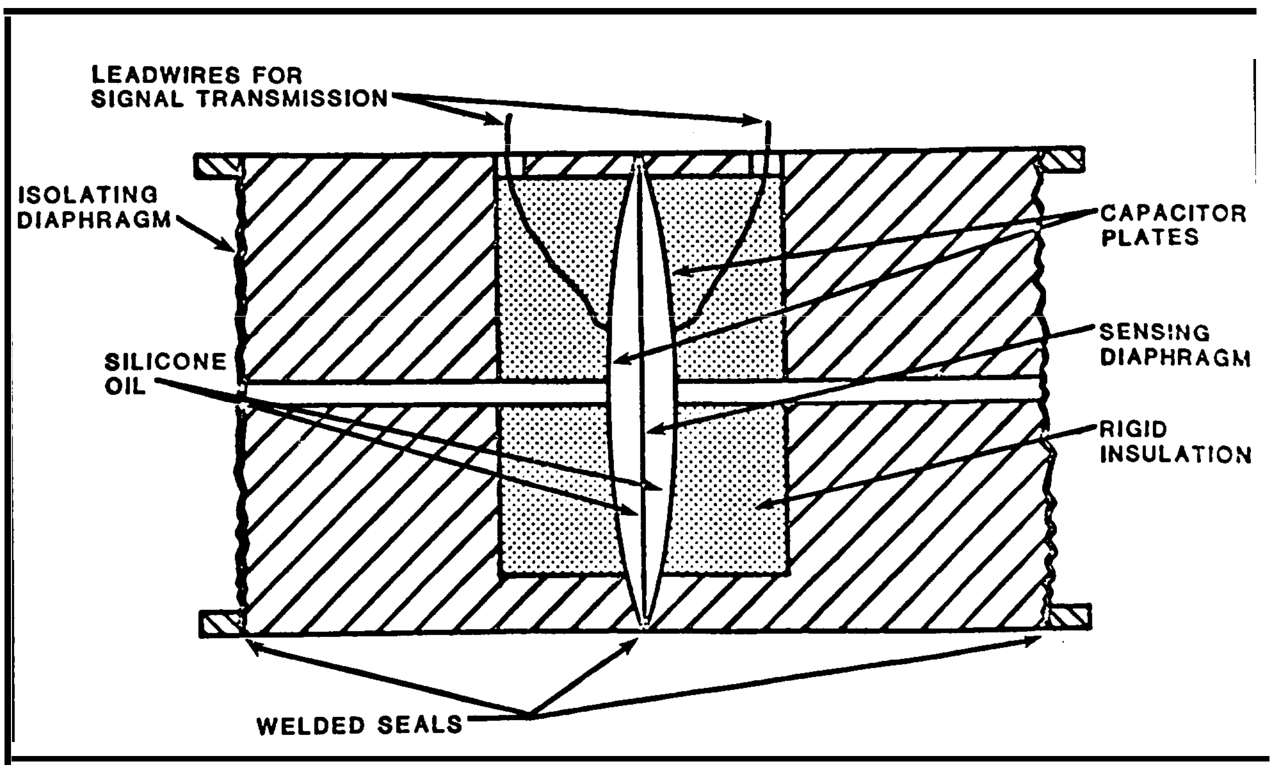


Figure 5-10. Electronic Device

Section 2. VENTURI TUBES

1. **INTRODUCTION.** Venturi tubes are used to measure flow in pipes and ducts. They can be applied to gases such as air and steam, and to liquids such as water and oil. Common applications include airflow in large ducts and steam output from boilers. Venturis are widely used, and a great deal of operating experience has been gained in a variety of applications. They are relatively easy to fabricate, consisting of a tube that gently converges to a low diameter throat and diverges to the downstream pipe diameter (Figure S-ll). If the cost of fluid delivery is high, venturis are desirable because they have a low, permanent pressure loss and do not decrease the delivery rate. Venturis have a low sensitivity to wear and are useful in erosive flows such as air with suspended solids. Venturi meters are especially applicable to large ducts, round or rectangular, where other types of flowmeters are expensive to fabricate and calibrate.

1.1 Operating Principles. Venturi tubes are inferential meters that do not measure flow directly, but cause differential pressure to occur. An inferred flow rate can be calculated by measuring change in pressure and by knowing proportional relationships. Figure 5-11 illustrates in a cutaway view, the venturi and the areas of high and low pressures associated with their respective velocities.

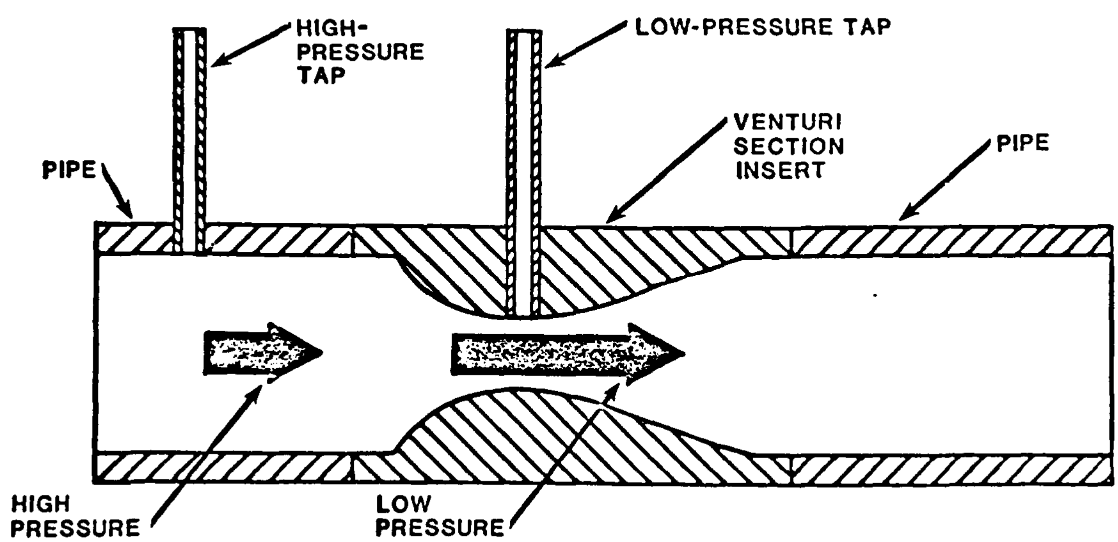


FIGURE 5-11. Venturi Tube

1.1.1 Venturi Tube/Orifice Plate Comparison. Venturi tubes can measure the same fluids as orifice plates. Like orfice plates, they can be built to match the size and shape of irregular piping. Venturi tubes cause less permanent pressure drop than orifice plates and are used more often where pumping costs are higher. Venturi tubes are less susceptible to wear from erosive fluids than orifice plate meters. However, as the size of venturi tubes increases, their *cost* increases more than that of orifice plates.

2. LIMITATIONS. The primary disadvantage of using venturi metering is their limited range. The maximum turndown ratio is limited to 4:1, which is inherent in the design. A marked change in flow conditions requires a new venturi configuration. Changing venturis is more expensive than orifice plates and requires a longer interruption of the system. Other considerations are as follows:

- Temperature limit is 1,000°F.

- Pressure limit is 6,000 psig.

3. INSTALLATION. The location of a venturi tube in the system is important. Whenever possible, it is preferable to locate the venturi tube in a horizontal line. To ensure accurate flow measurement, the fluid should enter the venturi tube with a fully developed velocity profile, free from swirls or vortices. Such a condition is best achieved by the use of adequate lengths of straight pipe, both preceding and following the primary element. The minimum recommended lengths of piping are shown in Figure 5-4. The diagram in Figure 5-4, that corresponds closest to the actual piping arrangement for the meter location, should be used to determine the required lengths of straight pipe on the inlet and outlet. These lengths are those necessary to limit errors due to piping configurations to less than +%0.5 percent. Minimum recommended distance is dependent upon the ratio of throat-to-inlet diameter. If minimum distances are not observed, the meter may produce inaccurate data.

4. MAINTENANCE. The following procedures are the minimum required for the most common types of units. When developing maintenance schedules, refer to the manufacturer's instructions. Perform the following tasks at the periods prescribed.

4.1 Quarterly Maintenance.

(a) Flush and clean annular chamber throat and inlet.

(b) Purge trapped air from chamber and connecting pipe.

(c) Clean pressure taps.

(d) Blow down sensor lines on a regular schedule.

(e) Check pressure taps for burrs and/or debris.

(f) Resize venturi if necessary, based on flow of previous year.

(g) Test dp transmitter every 6 months with dead weight pressure tester and rescale if necessary.

4.2 Annual Maintenance.

(a) Clean and paint exterior of meter.

(b) Dismantle and check for corrosion.

(c) Clean and restore smoothness to internal surfaces.

(d) Check flange gasket and replace if it is leading or intruding into flow path.

5. ACCURACY AND RELIABILITY. Accuracy is up to ±%0.75 percent of full scale. Accuracy is diminished at lowest turndown. Venturis are more reliable than orifice plate meters because they are less susceptible to wear.

6. DIFFERENTIAL PRESSURE DEVICES. Dp devices are used to provide a quantitative display of the differential pressure; they are also called delta P and ΔP devices. The four most common dp devices are: manometer, diaphragm, bellows and electronic. All new or replacement installations should be electronic.

6.1 Manometer. The manometer is a rather simple device. One end of the manometer is attached to the high-pressure tap and the other end to the low-pressure tap of the orifice plate installation. As the dp created by the orifice plate is sensed by the manometer, a column of fluid in the manometer allows the dp to be read directly on a scale (Figure 5-7). Refer to the manufacturer's instructions before installing a manometer.

6.2 Diaphragm. The diaphragm device includes a hermetically sealed diaphragm that is in an enclosure with one side open to the high-pressure tap and the other side to the low-pressure tap (Figure 5-8). The diaphragm moves as the dp created by the orifice meter is transmitted to the diaphragm chamber. A pointer attached to the diaphragm pivots about a fulcrum in the wall of the chamber and mechanically indicates the dp directly on a scale. Refer to the manufacturer's instructions before installing a diaphragm.

6.3 Bellows. A bellows device is similar to the diaphragm device in that the indicator pointer is attached to a component that is subject to movement caused by the dp. In a bellows device, a partition is hermetically sealed between two bellows in a confined compartment with an opening on one side to the high-pressure tap and another to the low-pressure tap (Figure 5-9). The input ends of the bellows are fixed to the compartment walls. As the dp forces the partition to move, compressing and expanding the respective bellows, a lever system causes a pointer to directly indicate the dp on a scale. Refer to the manufacturer's instructions before installing a bellows.

6.4 Electronic. Electronic devices are also known as capacitance devices. In an electronic device, the dp is transmitted through an isolating diaphragm to a hermetically sealed sensing diaphragm in the center of the device (Figure 5-10). The sensing diaphragm is surrounded by silicone oil contained between capacitors. As the sensing diaphragm deflects in proportion to the dp, the position of the diaphragm is detected by capacitor plates on each side of the diaphragm. The differential capacitance between the plates and the diaphragm is converted electronically to a 2-wire, 4-20 mA or 0-10 volt data transmission signal. Electronic devices are available in both square root and linear function models. Solid state, plug-in components simplify maintenance/repairs.

6.5 Calibration. Static calibration should be performed on all dp devices at least every 6 months.

6.6 Data Transmission. Readings from various dp devices must often be transmitted to remote data collection and recording sites. This is because the dp device may be too remote to warrant onsite reading. Data transmission may also be necessary because there may be many widely dispersed devices to be read and it would be uneconomical to have each one read onsite; or a central data management point has been set up to collect, record, plot, reduce, and analyze all flow data. All the taps for dp will accommodate remote transmission fittings along with the various dp devices.

6.6.1 Pneumatic. All the dp devices, except electronic, can have the readings transmitted to a remote site by pneumatic lines.

6.6.2 Electrical. Rather than pneumatically, the recommended means of data transmission is to have the dp electronically converted to an analog signal and transmitted electrically to a data collection center.

Section 3. PITOT TUBES

1. **INTRODUCTION.** Pitot tubes are used to q easure the flow of gas, steam, water, and other liquids in ducts and pipes. A pitot tube is a device that consists of a tube having a short, right-angled bend that is placed vertically in a moving body of fluid with the mouth of the bend directed upstream (figures 5-12 through 5-16). The most common applications include heating, ventilating, and air-conditioning (HVAC) systems and low velocity drafts. Pitot tubes are widely used as permanent and spot-check meters. Their characteristics are well known and information is widely available. Pitot tubes are generally less than l/2-inch in diameter and are inserted into the flow stream at right angles to the flow. Pitot tube meters measure the velocity of flow at only one point. If properly installed, they provide accurate and reliable flow measurement. Pitot tubes are suited for low to medium flow in large ducts. Due to their small size, pitot tubes cause very little permanent pressure loss. They are excellent for monitoring purposes because they are so portable and easily inserted and withdrawn from a flow stream.

1.1 Operating Principle. The principle used in a pitot tube meter is that when a flowing fluid impacts an object, its velocity drops to zero and the pressure at impact increases. The pitot tube measures the difference between impact (velocity) pressure and static pressure created at impact. Flow rate is determined by comparing the two pressures and the known relationship between pressure and flow rate.

2. **METER DESIGNS.** Differences in pitot tube designs are in the positioning of static and dynamic pressure taps that are used in measuring pressures and whether the installation is to be permanent or for temporary spot monitoring. Some designs place the taps separately, with the static tap located at the duct wall and the impact tap at the end of the pitot tube (Figure 5-12). Other designs locate both taps on the tube. A single point pitot tube infers the flow from single position readings.

Averaging pitot tubes have more than one impact hole along the leading edge of the tube (Figure 5-13). The static tap is generally placed on the downstream side of the tube. The tube is screw-fitted into place. The multiple impact holes provide for an averaging of the velocity across the pipe instead of at a single point. Cylindrical-bodied averaging pitot tube meters have proven to be nonlinear (and nonrepeatable) over most of the flow range. Only designs that incorporate some sort of vortex shedding body should be used. Both permanent and portable units can be used to measure flow rates of gases, air, and steam. The pitot tube is especially useful in odd-shaped or large ducting.

3. **RECOMMENDED APPLICATIONS.** Pitot tube meters are appropriate for measuring gas and steam flow in round pipes with diameters greater than 3 inches, especially when venturi tubes and orifice plates are too expensive to utilize or cause too great a permanent pressure drop. A pitot tube is recommended where developed flow is possible by assuring minimum straight lengths of pipe

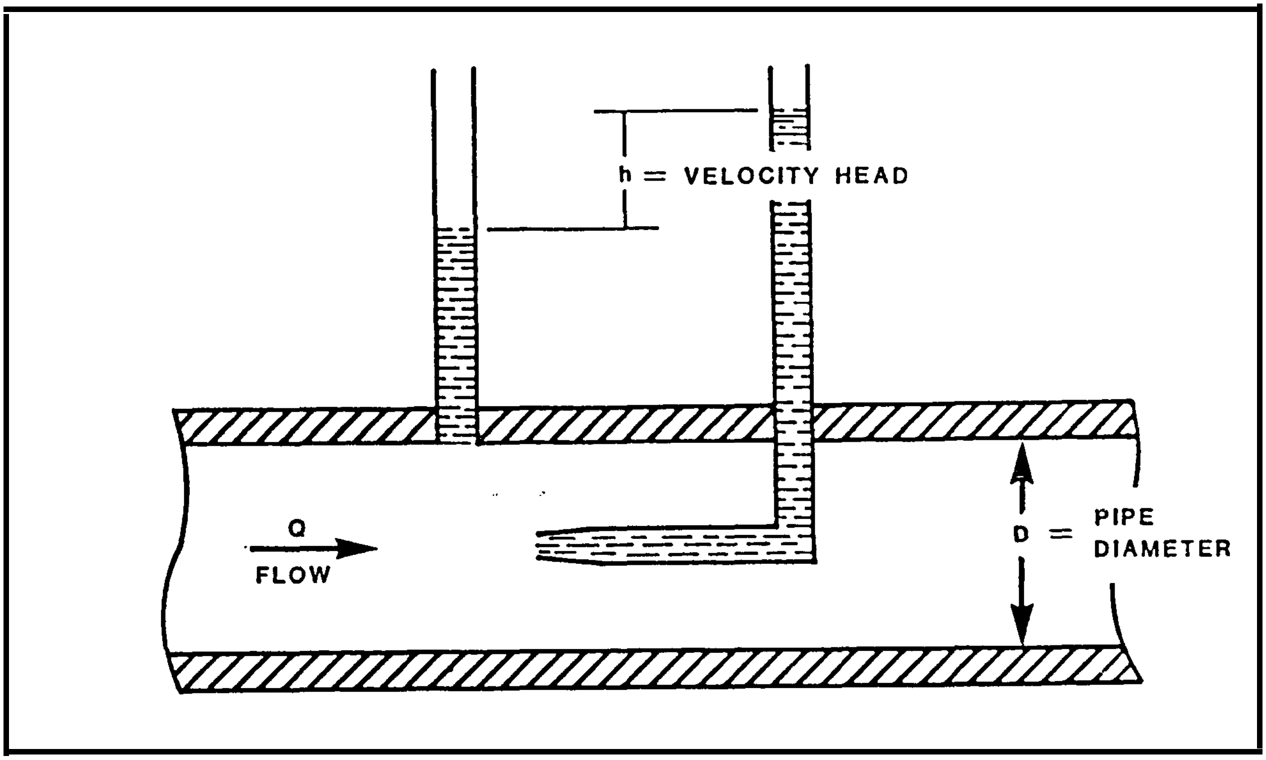


FIGURE 5-12. Pitot Tube Meter

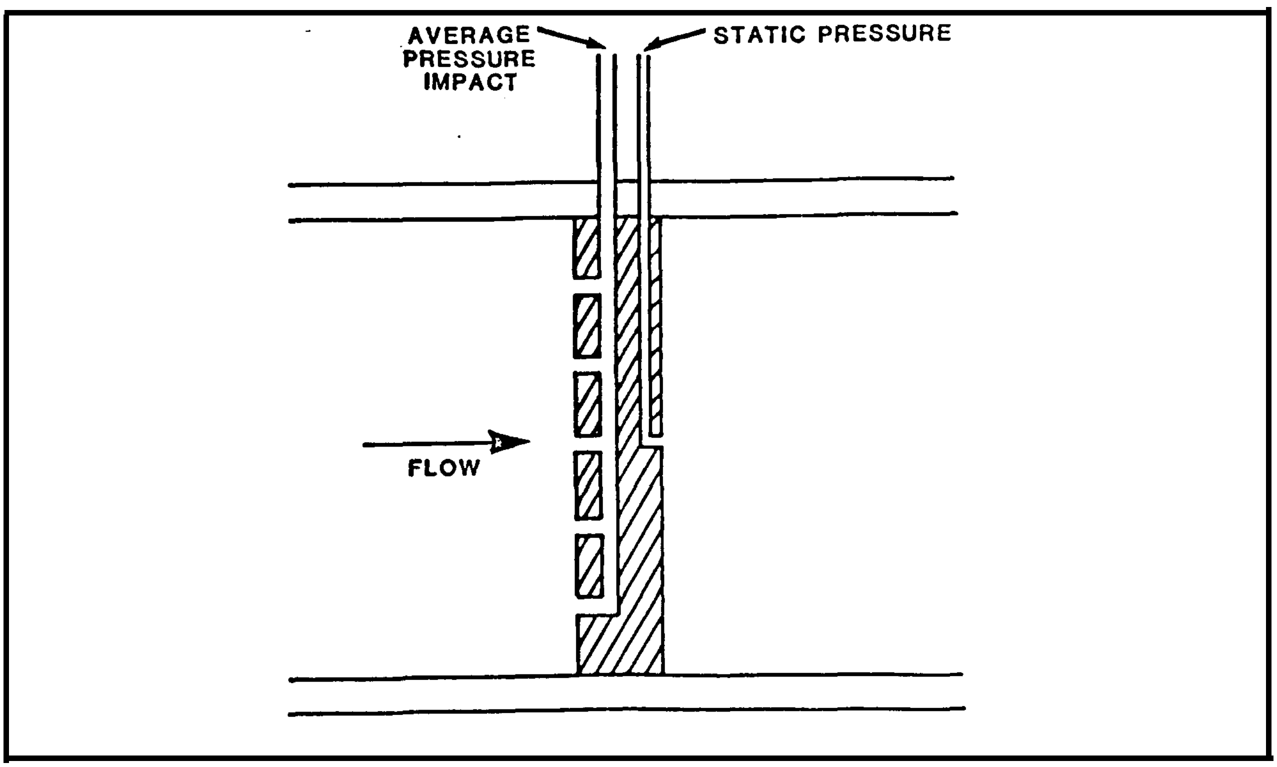


FIGURE 5-13. Averaging Pitot Tube

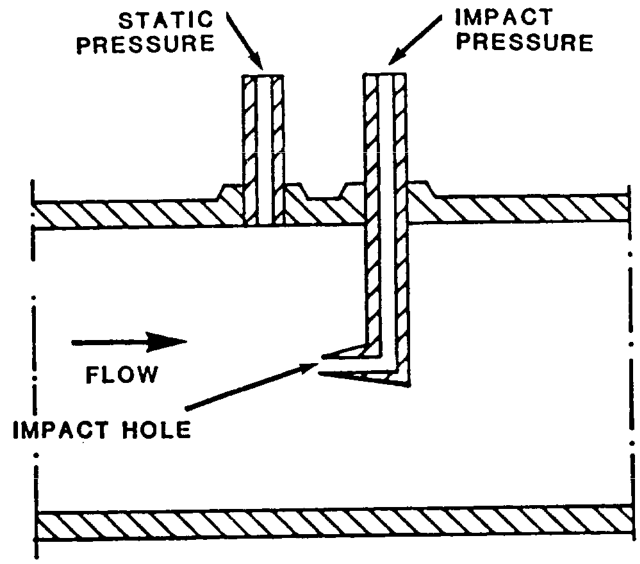


FIGURE 5-14. Single Hole Pitot Tube With Separate Static Tap

FIGURE 5-15. Hemispherical Head Pitot Tube

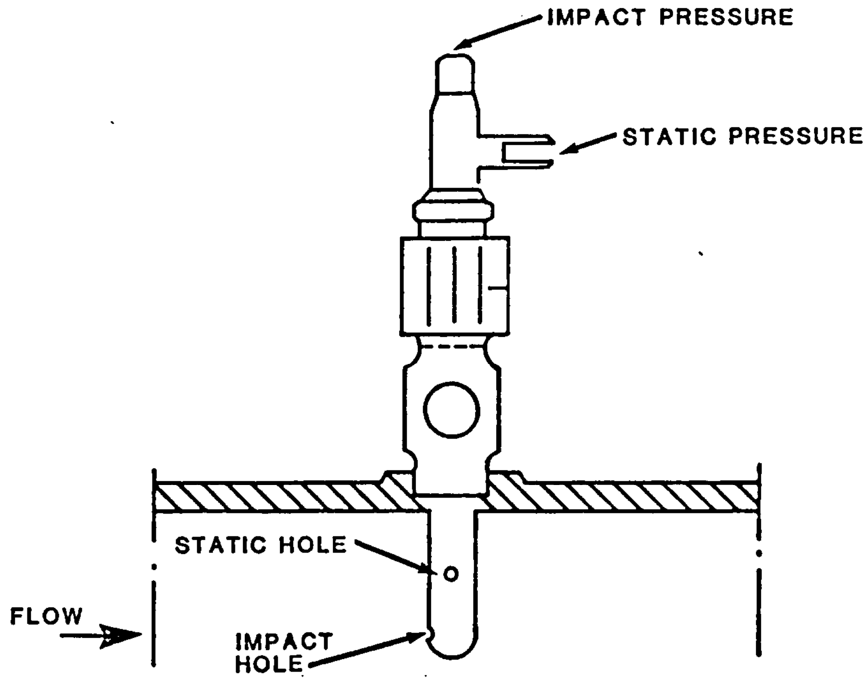


FIGURE 5-16. Commercial Pitot Tube

upstream and downstream of the tube. Permanent mountings are particularly attractive when repeated readings will be made but other meters are too expensive.

4. LIMITATIONS. The use of a pitot tube meter at a specific location may be limited by the following requirements:

- Only clean fluids can be measured.
- A recommended minimum length of straight pipe is required.
- Meter is susceptible to errors when metering an undeveloped or disrupted flow profile.
- Temperature is limited to 537°C (1,000°F).
- Pressure limit is 6,000 psig.
- Turndown is limited to approximately 3:1. (Range can be increased by stacking dp transmitters.)

5. INSTALLATION. Figures 5-13 through 5-16 illustrate a variety of pitot tube installations. The static pressure tap can be located either on the pipe or duct or be incorporated in the pitot tube itself. The pitot tube is

inserted at right angles to the flow. The impact port must meet the flow squarely. Placement of the tube is critical. The pitot tube measures velocity at only one point. The single point is used to calculate average flow velocity, but does not necessarily represent average velocity ($v_{critical}$). In small lines, it may be impossible to place the pitot tube at $v_{critical}$ because of the pipe wall. It may be necessary to measure flow at multiple locations to establish a relationship between the final pitot tube location and the actual flow. It is preferable to locate the pitot tube in a horizontal line. To ensure accurate flow measurement, the fluid MUST enter the pitot tube with a fully-developed velocity profile, free from swirls or vortices. Such a condition is best achieved by the use of adequate lengths of straight pipe, both preceding and following the pitot tube. The minimum recommended length of upstream piping is 7.5 times the pipe diameter. For specific lengths for a particular installation, consult manufacturer. The length is necessary to limit errors, due to piping configurations, to less than ±%0.5 percent. If minimum distances are not observed, the pitot tube meter may produce inaccurate data. In ducts that do not meet straight length requirements, it is necessary to take multiple samples to obtain an adequate flow profile.

5.1 Permanent Mounting With Separate Static Tap. In this option, the pitot tube impact tap is permanently mounted facing directly upstream. It is located at a point where the velocity measured represents average velocity. The static tap is drilled through the wall of the pipe less than one-half pipe diameter upstream of the impact tap. Both taps are for screw-fitted components.

6. MAINTENANCE. The following procedures are the minimum required for the most common types of units. When developing maintenance schedules, refer to the manufacturer's instructions. To ensure reliable flow data, the following actions must be undertaken quarterly or when data accuracy is suspect:

- Check for clogged orifices.
- Check tip for wear.
- Sensor lines should be blown down on a regular schedule.
- Rescale dp transmitter if necessary, based on flow of previous year.
- Test dp transmitter with dead weight pressure tester and rescale if necessary.

7. ACCURACY AND RELIABILITY. Accuracy is typically ±%5.0 percent of full scale. For specific applications, accuracy can be up to ±%0.75. Pitot tubes are reliable as long as the fluid being measured is sufficiently clean to avoid clogging the orifices. With contaminated or dirty fluids, Increased maintenance may be necessary to ensure accuracy.

Section 4. VARIABLE ANNULAR ORIFICE METERS

1. **INTRODUCTION.** Variable annular orifice meters are permanently installed in piping to measure mass or volume flow of gases, liquids, or vapors. Variable annular orifice meters do not have a fixed orifice area as do other differential pressure meters, i.e., orifice plate, pitot tube, and venturi. Variable orifice meters produce results on a linear scale, with large rangeability, reliable repeatability, and greater operating temperature range. The-flow rate measurements may be read and recorded locally or remotely.

1.1 Meter Designs. Changing the area of the orifice with relation to flow rate is accomplished in variable annular orifice meters by two main designs. One design uses a movable plug, the other uses a movable orifice.

2. **OPERATING PRINCIPLES.** Introduction of an orifice into a flow line produces a differential pressure that is measurable and relative to the flow rate. If the area of the orifice is fixed, the differential pressure produced is dependent upon inlet swirl and velocity profile and is proportional to the square of the velocity of the fluid. This results in a nonlinear scale and small rangeability. However, if the orifice is annular and its area increases with the flow rate, the differential pressure is directly proportional to the flow rate. Variable orifice meters do change the area of the orifice in relation to flow rate by axial movement of a plug or bellows.

2.1 Movable Plug. The movable plug design has a fixed orifice with a contoured plug mounted on a movable shaft (Figure 5-17)0 AS the flow rate increases, the plug moves axially in the direction of flow resulting in a larger orifice area. This produces a pressure drop that is linear and directly proportional to the flow rate.

2.2 Movable Orifice. The movable orifice design has a fixed contoured plug and provides for the movement of the orifice that is attached to a bellows (Figure 5-18). As the flow rate increases, the bellows compresses causing an increase in the annulus. This enlargement of the annulus results in a pressure drop that produces a differential pressure change directly proportional to the flow rate.

3. **APPLICATIONS.** Variable annular orifice meters are versatile in their application. Specific operating characteristics and capabilities are dependent upon the manufacturer. Generally, they can be used with most liquids such as water, petroleum distillates, chemical compounds, and crude oil. Use with gases is virtually unlimited. Metering of vapors includes steam, ammonia, and Freon.

4. **LIMITATIONS.** The major limitation of the variable annular orifice meter is that it requires system shutdown for installation since it is located axially in the pipe. Because variable annular orifice meters have moving

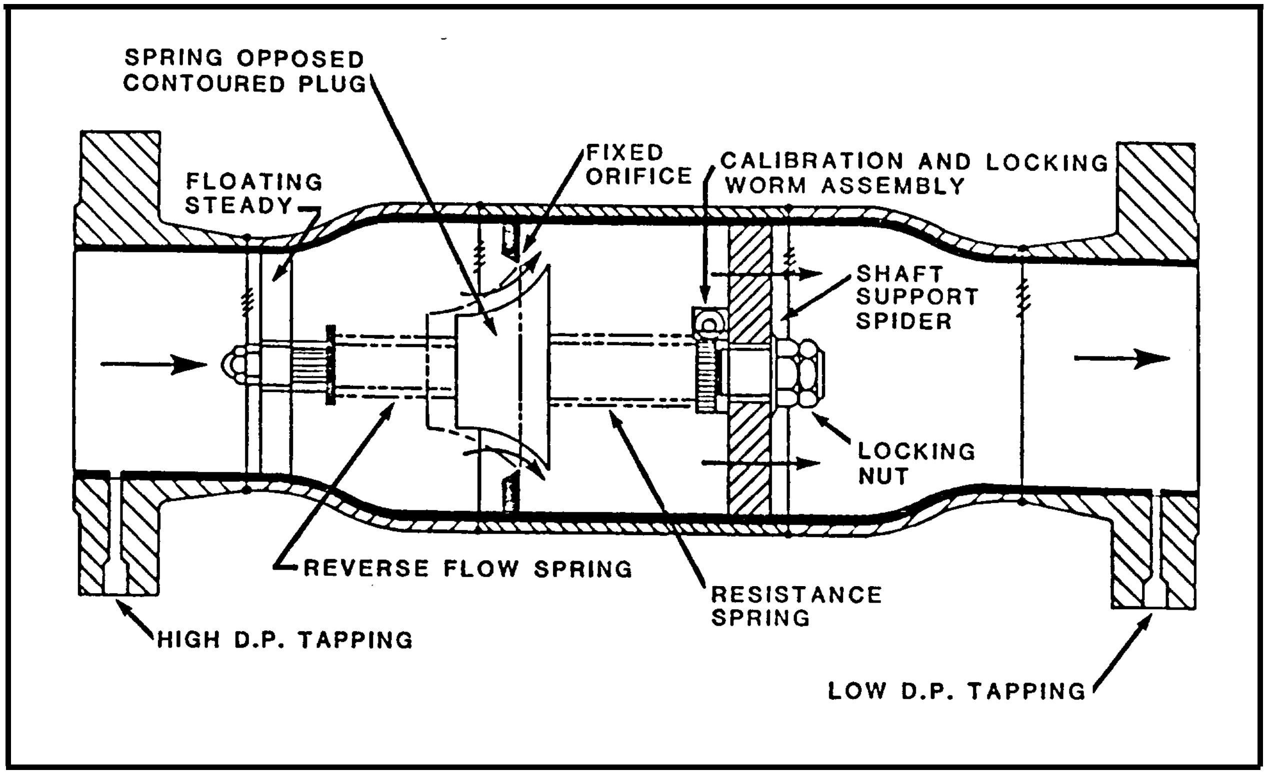


FIGURE 5-17. Movable Plug

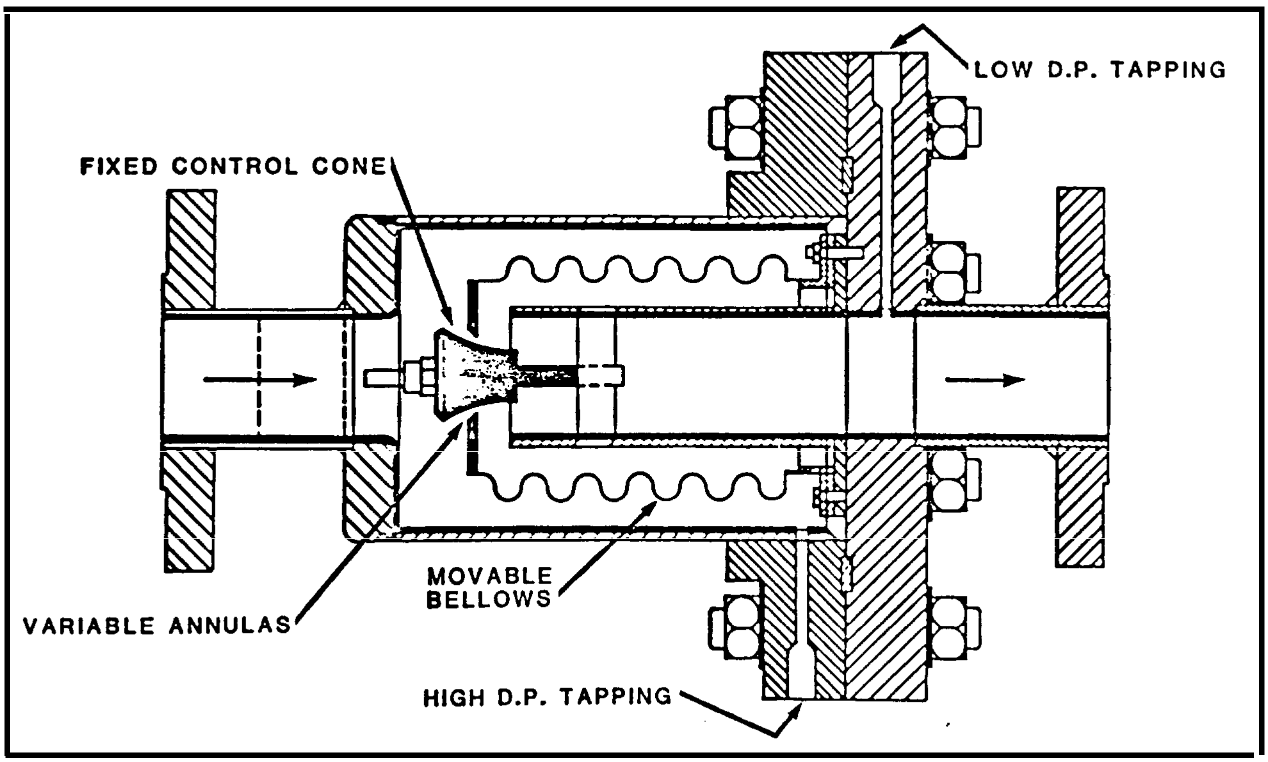


FIGURE 5-18. Movable Orifice

parts, any improper functioning of a moving part can be considered a limitation. Limitations associated with standard operating ranges are as follows:

- Temperature range: -200°C (-328°F) to +460°C (+860°F)
- Pressure range: 0 to 2,500 psi
- Maximum viscosity: 100 cps
- Turndown ratio: 100:1
- Pipe size: 1/2- to 16-inch
- Straight pipe requirements: 6D upstream and 3D downstream

5. **INSTALLATION.** Installation of a variable annular orifice meter is similar to repairing a section of pipe or installing a T-section. The line must first be shut down. A section of the pipe is removed and mounting flanges that accept the flanges of the respective meter are put in place. The meter is then attached according to manufacturer's recommendations. A distinct advantage of the variable orifice meter is that usually only six diameters (6D) of straight pipe are required upstream of the meter installation and three diameters (3D) downstream. Sensor mountings can be for local or remote readout. Attachments for remote reading may be for pneumatic or electronic transmission.

6. **MAINTENANCE.** Maintenance on the most common variable annular orifice meters is negligible, but the dp cell, sensors, data transmission lines, and processor require regular monitoring and maintenance. Maintenance schedules should be developed according to manufacturer's recommendations. The only components that may require attention are the contoured plug and the movable bellows. Since inspection requires system shutdown, it is warranted only if an unreasonable or unexplainable change occurs during regular monitoring of meter data. Monitoring of data is a viable indicator for needed inspection since the repeatability of these meters is usually 0.25 percent of full scale.

7. **ACCURACY AND RELIABILITY.** The accuracy of variable annular orifice meters is ±%1.0 percent of full scale if calibrated to specified tolerances. No specific quantitative data is available on the reliability of variable annular orifice meters, but the mean-time-between-failures is usually a matter of years. Repeatability over the entire range contributes significantly to the large turndown ratio.

CHAPTER 6. VELOCITY METERS

Section 1. TURBINE AND FAN METERS

1. **INTRODUCTION.** Turbine and fan meters are inferential type meters. Both determine actual flow by relating rotational speed of a moving element, which acts as a turbine or fan, placed in the flow stream.

1.1 Operating Principles. Turbine and fan flowmeters use kinetic energy of a flowing fluid to drive a turbine or fan which generate frequencies proportional to flow rate. The rotational velocity of the rotating element and the fluid velocity are linearly proportional over the working range of the meter.

2. **METER DESIGNS.** All turbine and fan meters consist of a rotating element or rotor. Rotor speed is linearly proportional to fluid velocity.

2.1 Turbine Meter. Turbine meters consist of a multiblade rotor mounted within a pipe perpendicular to the fluid flow (Figure 6-l). The rotor spins as the liquid passes through the blades. The rotational speed is a direct function of flow rate and can be sensed by q agnetic pickup, photoelectric cell, or gears.

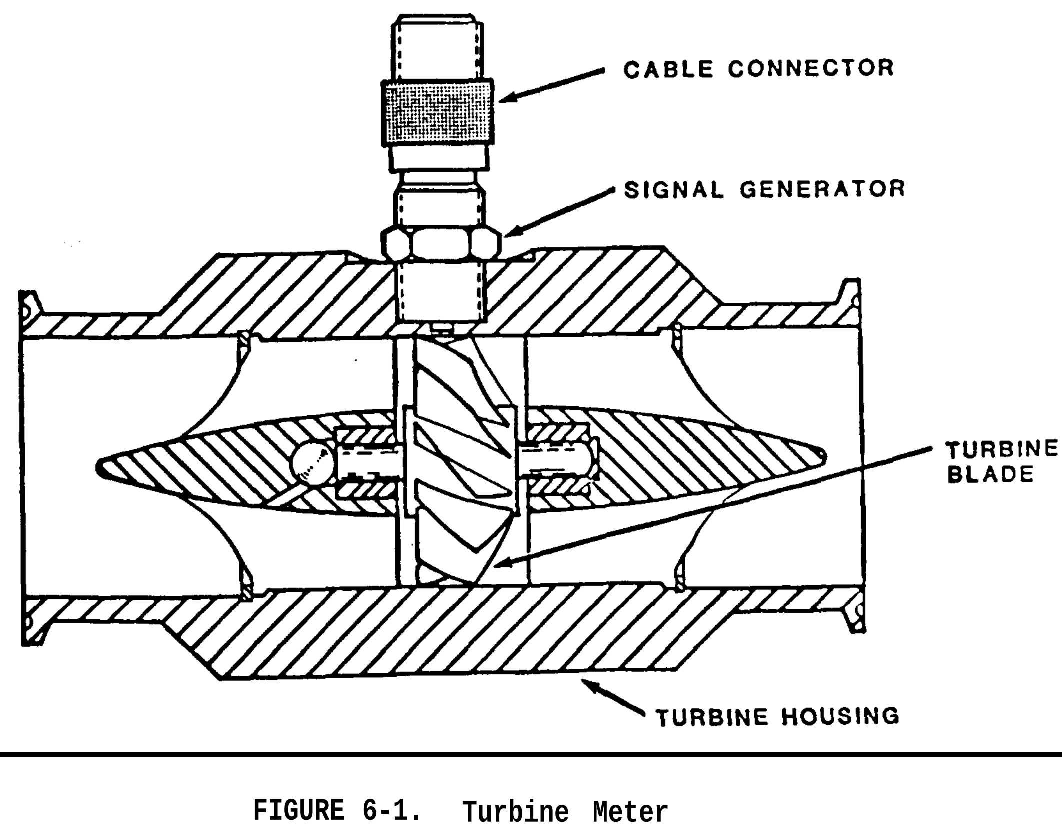


FIGURE 6-1. Turbine Meter

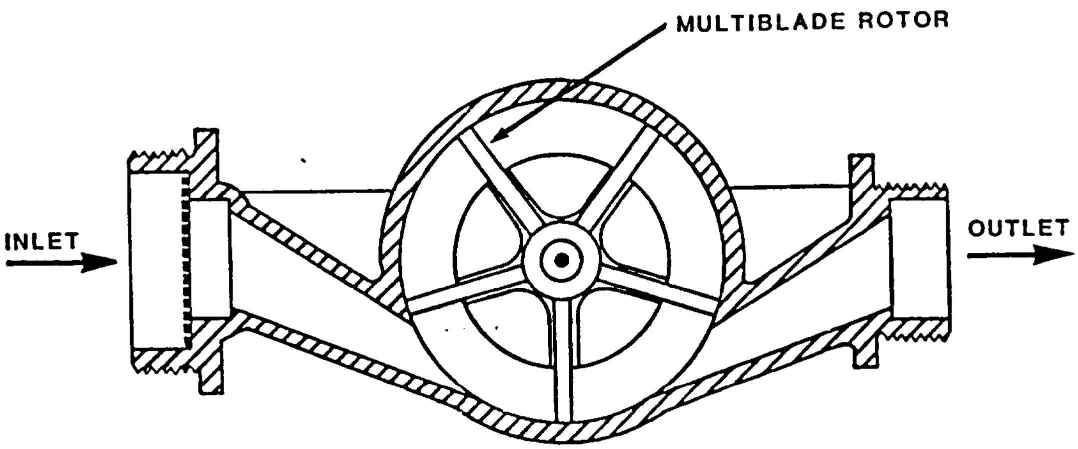


FIGURE 6-2. Fan Meter

2.2 Fan Meter. Fan meters consist of a housing with a multiblade rotor mounted on a spindle at right angles to the direction of flow (Figure 6-2). Flow enters the meter case, strikes the rotor tangentially, causing rotation. The speed of rotation is determined by the velocity of the liquid and the configuration of the chamber and rotor. Single jet type q eters are the simplest example. In the single jet meter, fluid enters the meter through a single tangential inlet. A single outlet port is located diametrically opposite the inlet. The multijet type meter has the same general features as the single jet meter. Liquid enters the working chamber of the multijet meter through a number of tangential inlets around the circumference and leaves through another set of orifices placed at a higher level in the chamber.

2.3 Pressure Losses. Pressure losses in turbine and fan meters are substantially less than orifice plate meters. Expected pressure loss is in the range of 0.4 to 0.8 psi.

3. TURBINE METER. The turbine meter is used more often than the fan meter. The rotor is helical and is mounted on a shaft parallel to the flow direction. Turbine flowmeter rotors are supported by ball bearings or ball sleeve bearings. Bearings are exposed to the process as long as the flowmeter is in the process pipeline. Bearing life depends on several factors. One factor is the floweter duty cycle, the actual operation expressed as a percentage of total time. Bearing life also is related to corrosion resistance and type of corrosive impurities in the process. Lubricating qualities and cleanliness of the process stream have a positive effect on

bearing longevity; abrasiveness of solid particles present has a negative effect. Hard, abrasive particles in the process stream are the major cause of turbine flowmeter bearing wear. To minimize stream contamination by solids, a strainer should be installed upstream of the turbine flowmeter. Recommended strainer mesh sizes are given in specific product literature.

3.1 Turbine Meter Designs. Turbine meters are applied in two distinct designs, full-bore and insertion types. Full-bore turbine meters have a rotating element equal to pipe diameter; they measure the total flow. Turbine meters are available for pipe sizes greater than one-half inch in diameter. They are designed for liquid or gas measurement. Full-bore turbine meter costs increase exponentially as line size increases, making them uneconomical for large line sizes. Insertion meter costs are the same regardless of line size, making them an attractive alternative. Insertion meters measure a sample of fluid flow at a local velocity. Insertion meters can be used to measure liquid, gas, and steam when pipe sizes are 3 inches or larger (Figure 6-3).

3.2 Recommended Applications. Full-bore meters are primarily applied either to clean, low particulate fuel oil or water. Corrosive materials can be q easured if a stainless steel rotor is used. Turbine meter applications for steam measurement must be so specified to obtain the correct bearing and turbine materials. Insertion meters are excellent for steam applications. The small, low inertia rotor has a rapid response time. In addition, cost of the meter is independent of the pipe size. Whether the full-bore or insertion type meter is used, the turbine meter is often chosen because of its turndown ratio. Turbine meters have a minimum flow turndown ratio of 10:1. Turndown ratio can be up to 50:1 depending on pipe size and fluid velocity. An insertion turbine meter can also be used as an analytical tool. Because of its ability to move across a pipe section and to orient the rotor head at various angles to the flow stream, the meter can determine the nature of unsymmetrical flow patterns and detect any swirl within the pipe. Turbine meters have an advantage over other types of meters because they are capable of measuring forward and reverse flow.

3.3 Limitations. Several of the limitations that may preclude application of a turbine meter are as follows:

- Turbine meters are restricted to clean fluids.

- Insertion turbine meters require a clear space of at least 4 feet perpendicular to the pipe for installation.

- Temperature operating range for standard units is -73°C (-100°F) to +427°C (+800°F). Special ranges are available.

- Pressure limit is 3,000 psig.

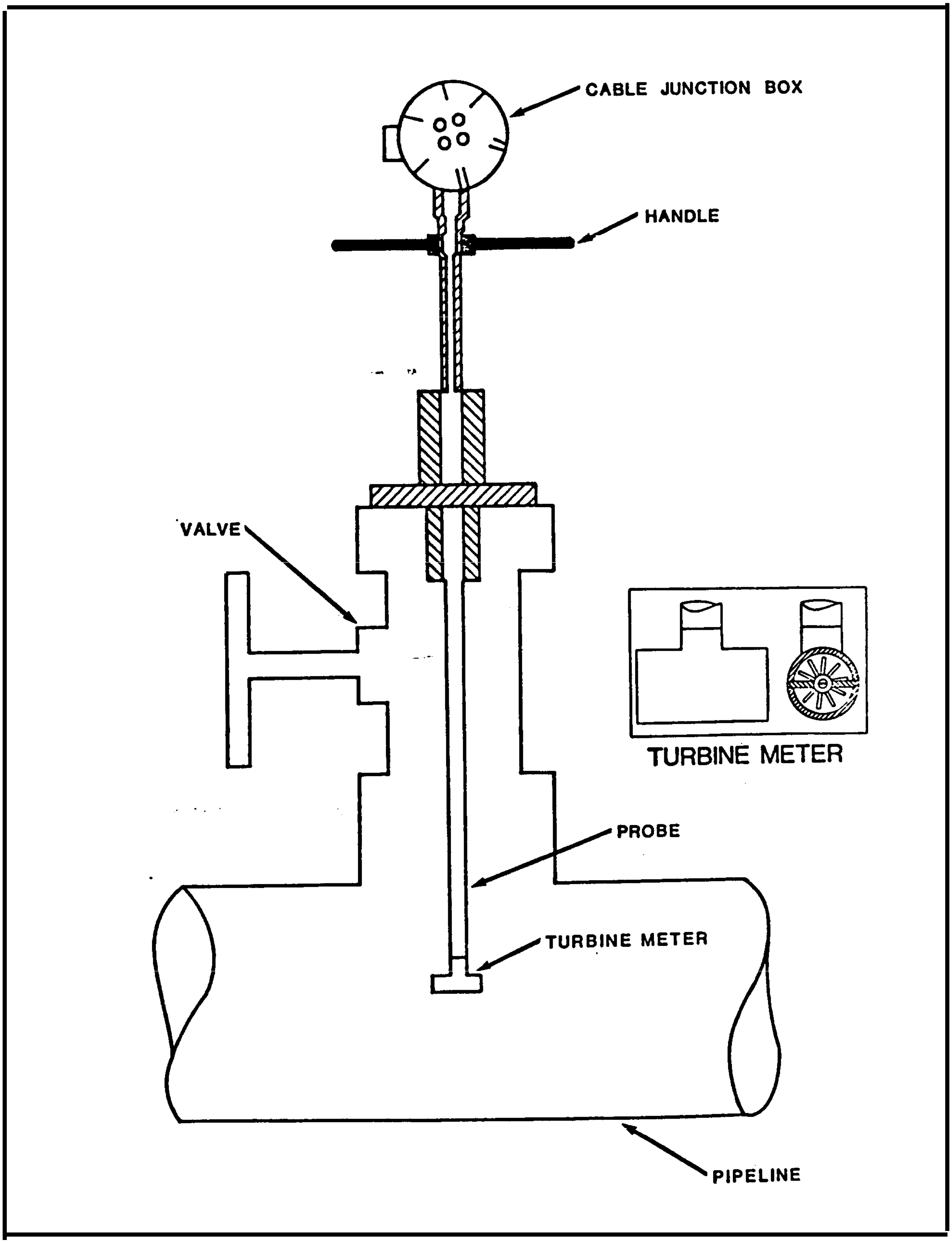


FIGURE 6-3. Insertion Turbine Meter

3.4 Accuracy and Reliability. The turbine meter is highly accurate through q ost of its range. Guaranteed accuracy of ±%1.O percent is available. Insertion meters are subject to the inaccuracies that result from locally measuring an average velocity. Reliability of properly installed and maintained turbine meters should yield a 4-1/2 year mean-time-between-repair and a total life expectancy of 10 to 25 years.

4. SHUNT METERS. Shunt flowmeters are a special class of turbine meters which use an orifice plate to control a bypass flow metered by the turbine.

4.1 Operating Principles. The turbine rotation is at a speed proportional to a bypass flow controlled by an orifice plate, which in turn is proportional to the main flow rate. A reduction train, that gears down the turbine, is coupled to a driving magnet. The magnet influences another magnet that is the counter. The two magnets operating in unison enable totalization of the turbine rotation.

4.2 Meter Design. There are two types of shunt meters. One is external to the main flow pipe, *as* shown in Figure 6-4. The other is mounted as an inline meter within the main pipe. Neither type requires power for totalization.

4.3 Limitations. The limitations of a shunt meter are as follows:

- Requires system shutdown to install.
- High maintenance and difficulty in calibration.
- Costs are moderate to high.
- Turndown ratio is 7 to 1.
- Not recommended for steam below 30 psig or over 200 psig.
- Not recommended for fuel oils.
- Not recommended for air or natural gas below 5 psig.
- Permanent pressure loss due to orifice plate.

4.4 Installation. The flow in the line must be turned off during installation of a shunt meter. A diversion orifice plate with flanges must be placed in the main line. Holes must be cut into the main line before and after the orifice plate to accept the bypass piping which contains the turbine and counter box (Figure 6-4).

4.5 Maintenance. Maintenance should be performed every 6 months. The diversion orifice plate should be checked for wear and the turbine blades for deformation. The counter should be checked for accuracy and calibrated if necessary.

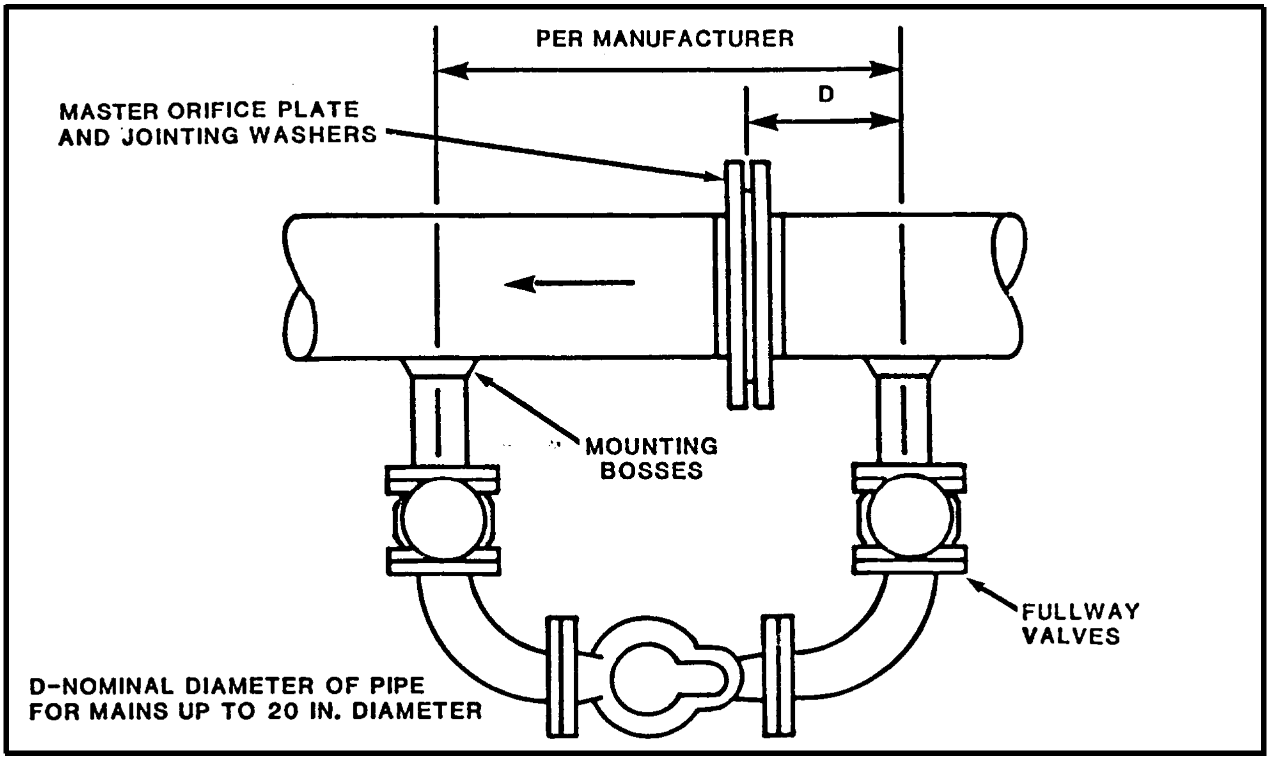


FIGURE 6-4. Shunt Meter

4.6 Accuracy. The accuracy of shunt meters is as follows:

- Accuracy: ±%2.0 percent of reading
- Linearity: ±%2.0 percent
- Repeatability: ±%2.0 percent

5. FAN METERS. A second type of rotational inferential meter is the fan meter (Figure 6-2).

5.1 Recommended Applications. The use of fan type meters is limited to cold and hot water flow measurement. Fan meters have wide ranges and turndown ratios greater than 10:1 are common. Pressure drop associated with fan type meters increases proportionately with flow rate. Typically, permanent pressure drop for this type of meter is less than 1.0 percent at all flow conditions.

5.2 Limitations. Several limitations that may preclude application of a fan type meter are as follows:

- Fan type meters are restricted to clean fluids.
- Meter installation should be horizontal and level.
- Temperature range is from -267°C (-450°F) to +260°C (+500°F).
- Pressure limit is 3,000 psig.

5.3 Accuracy and Reliability. Fan type meters are typically not as accurate as turbine or positive displacement meters. They have an accuracy of ±%1.5 percent over the flow range. Reliability is comparable to turbine meters. If installation is proper and maintenance is performed as required, the meters can be expected to have a 4-1/2 year mean-time-between-repair and a total life expectancy of 10 to 25 years.

6. INSTALLATION. Installation of turbine and fan type flowmeters involves placement of the sensing element directly in the flow channel. The location of the turbine or fan meter in the system is important. Whenever possible, it is preferable to locate the primary element in a horizontal line or a vertical line with flow in the upward direction. To ensure accurate flow measurement, the fluid should enter the primary element with a fully developed velocity profile, free from swirls or vortices. Such a condition is achieved by the use of strainers, straightening vanes, and/or adequate lengths of straight pipe preceding and following the primary element. Using a beta ratio of 0.6, typical ASME recommended lengths of such piping are shown in Figure 6-5, but specific requirements should be obtained from the manufacturer. The diagram in Figure 6-5 that corresponds closest to the actual piping arrangement for the meter location should be used to determine the required lengths of straight pipe on the inlet and outlet. These lengths are necessary to limit errors due to piping configurations to less than ±%0.5 percent. If minimum distances are not observed, applying flow equations and calculations may result in inaccurate data. Full-bore meters require shutdown of the system during installation, periodic inspection, and maintenance, but insertion type meters can be hot-tapped and do not interrupt the system for installation or removal. Turbine and fan flowmeter installations must also take into consideration the following items:

- Reduce turbulence by observing recommended straight length distances.
- Care should be taken to place the meter as far from valves and other turbulence-producing fittings as possible. All regulator and control valves should preferably be located downstream of the meter; if upstream, beyond the recommended straight length distance.
- If used, place straightening vanes and strainers upstream of the meter.

- When metering liquids, a "horizontal" line should gently slope upward for a sufficient distance downstream of the flowmeter to ensure that it will always be filled with liquid.

7. **MAINTENANCE.** The following procedures are the minimum required for the most *common* types of fan and turbine units. *When* developing maintenance schedules, refer to the manufacturer's recommendations.

7.1 Annual Maintenance. Annually, remove the meter head and inspect as follows:

(a) Ensure that the rotor has *no* obvious signs of deterioration, abrasion wear, or fouled debris.

(b) Ensure that the rotor shaft and bearings are not excessively worn, are free of debris, and the propeller turns freely.

(c) Return insertion turbine rotor to the manufacturer for recalibration.

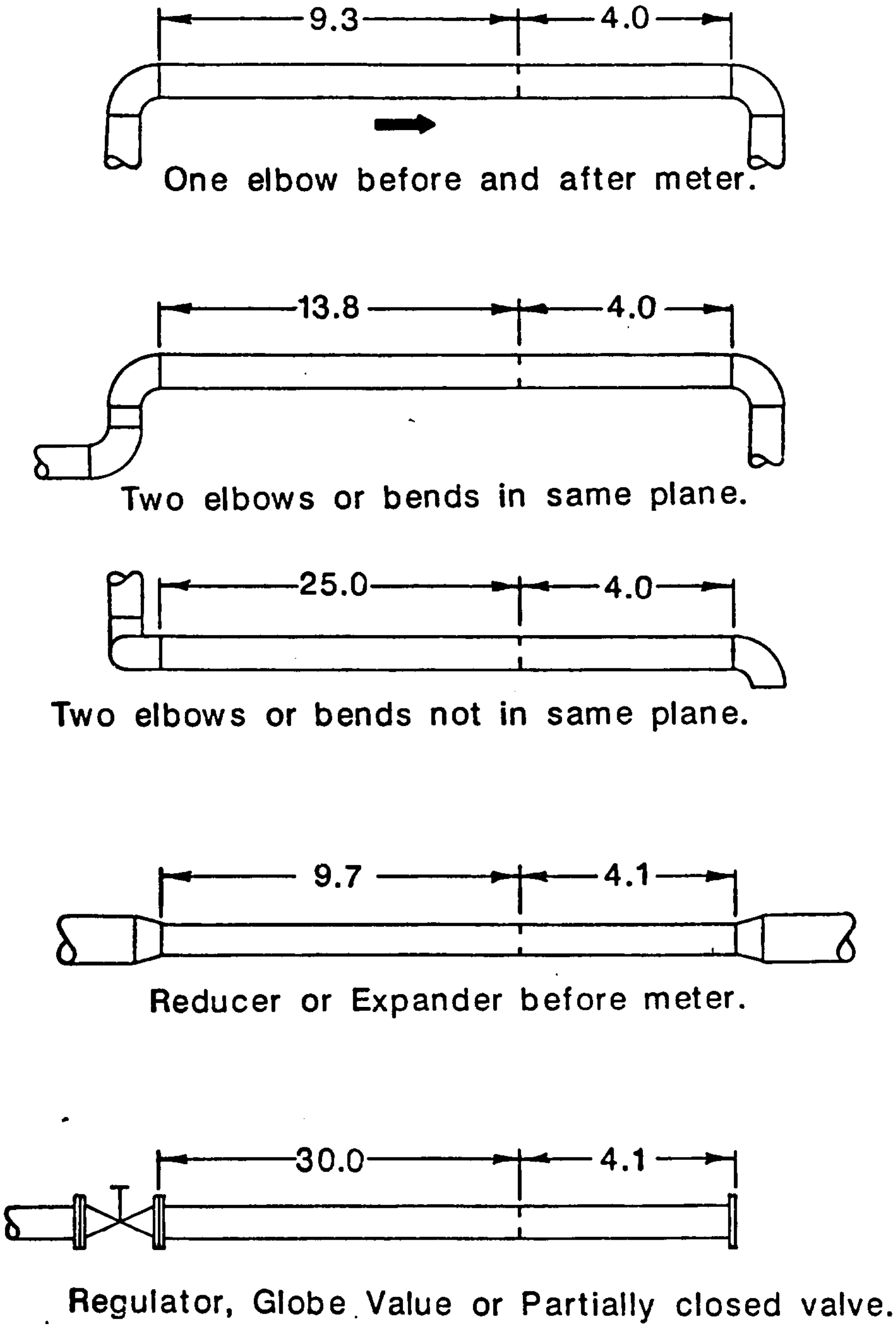


FIGURE 6-5. Minimum Straight Length Piping for Turbine and Fan Meters

Section 2. VORTEX SHEDDING METER

1. **INTRODUCTION.** A vortex shedding meter consists of a bluff body to develop vortices, and an electronic sensing device to monitor the number and rate at which vortices are shed. Vortex shedding meters have a wide turndown ratio and temperature range. This type meter is commonly used to measure liquids, gases, and steam. Vortex shedding meters are available in full-bore or insertion models.

1.1 Operating Principles. Vortex shedding is the natural effect that occurs when a gas *or* liquid flows around an obstruction or bluff body (Figure 6-6). When flow encounters a bluff body on its downstream course, it separates from the surface of the bluff body, leaving a highly turbulent wake that takes the form of a vortex. Each vortex grows and then becomes detached or shed from the bluff body. These shed vortices travel downstream in a fixed, predictable pattern. The number of vortices shed from the strut per unit time is proportional to fluid flow rate. This vortex frequency is detected with a sensor, which transmits a signal to a totalizer or other metering device.

2. **METER DESIGNS.** All vortex shedding meter designs consist of two main components, the bluff body and the sensing device. There are many different bluff body configurations. In some instances multiple struts are incorporated into the design.

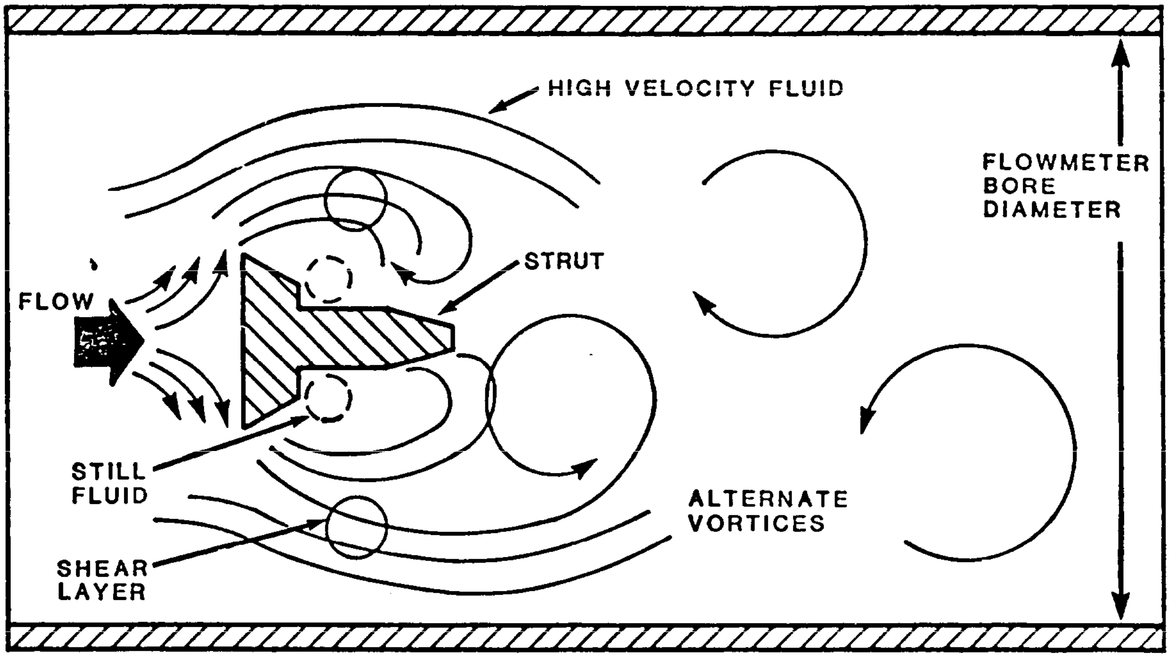
2.1 Bluff Bodies. Figure 6-6 illustrates three different strut configurations. Though the shape differs, actual dimensions of the bluff body are determined by the relationship between the diameter of the pipe, the viscosity of the fluid, and the flow rate. The strut must have nonstreamlined edges so that vortex formation can occur.

2.2 *Sensors.* There are four types of sensors commonly used to detect vortices developed by the bluff body and shed into the downstream flow: strain gauge, magnetic pickup, ultrasonic detector, and piezoelectric element.

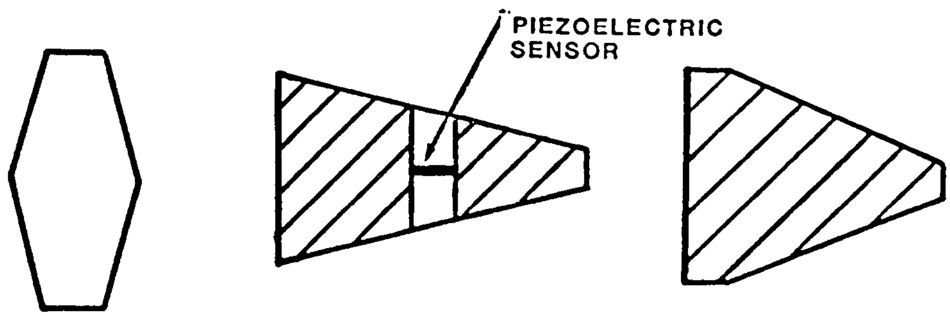
3. **VORTEX SHEDDING METER CONFIGURATION.** There are two vortex shedding meter configurations, full-bore and insertion. The use of one or the other is dependent on whether the metering is to be permanent or periodic and whether or not the pipeline can be shut down for installation.

3.1 Full-Bore Meters. The full-bore vortex meter, which is the same diameter as the pipelines is permanently mounted between pipeline flanges. If permanent metering is planned at the time of initial pipeline construction or during pipeline retrofit, the full-bore meter is usually installed. The full-bore meter has fittings for signal amplification and transmission to recorders and dataloggers.

3.2 Insertion Meters. Insertion meters are small, vortex-shedding devices designed to be inserted through fittings and valves permanently affixed to the system. They are used for obtaining either long term or periodic flow information. There are two types of insertion meters, fixed and hot tap.



SHEDDING PRINCIPLE



STRUT CONFIGURATIONS

FIGURE 6-6. Vortex Shedding Meter

Fixed insertion meters are used on systems where the pressure can be relieved during installation and removal of the meter. Hot tap insertion meters are designed for use where system monitoring is necessary without interrupting line pressure. The meter is inserted through a full-port ball or gate valve. Hot tap meters require probe length clearance above the mounting flange and valve to allow full retraction and removal of the meter.

4. RECOMMENDED APPLICATIONS. Vortex shedding meters are designed for use on clean gas and liquid systems, but they are commonly used on dirty gases and dirty or corrosive liquids which decrease meter life expectancy.

5. LIMITATIONS. The recommended applications for vortex shedding meters require the consideration of the following limitations:

- Inaccurate at low fluid velocities compared to turbine meters.
- Space availability above the flange for insertion meters.
- Alignment and location are critical.
- Working pressure limit of 1,500 psi.
- Common temperature limit of 560°F.
- Pipe size of 1- to 8-inch diameter.

6. INSTALLATION. The location of a vortex shedding meter in a system is important. Whenever possible, it is preferable to locate the primary element in a horizontal line. To ensure accurate flow measurement, fluid must enter the primary element with a fully-developed velocity profile, free from swirls or vortices. Such a condition is best achieved by use of adequate lengths of straight pipe, both preceding and following the primary element. Straightening vanes can preclude the need for long lengths of straight pipe. The minimum recommended lengths of piping are shown in Figure 6-7. The configuration in Figure 6-7 that corresponds closest to the actual piping arrangement for the meter location should be used to determine required lengths of straight pipe on the inlet and outlet. These lengths are those necessary to limit errors due to piping configurations to less than ±0.5%. If these minimum distances are not observed, the flow equations and resultant flow calculations may result In inaccurate data. For specific applications, refer to manufacturer’s installation criteria,

7. ACCURACY AND RELIABILITY. Vortex shedding meters have an accuracy of ±1.0% when calibrated, with a turndown capability up to 10:1 dependent upon pipe size and fluid properties. The lack of moving parts results in reduced maintenance and makes this type of measuring device a very reliable means of flow measurement.

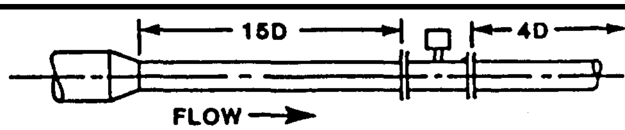
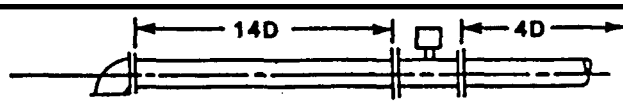
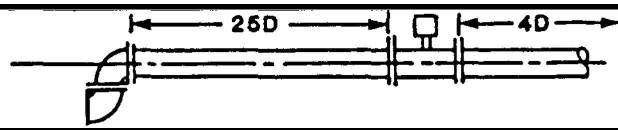
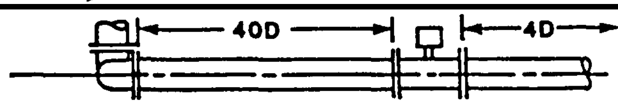
RECOMMENDED MINIMUM STRAIGHT PIPE (D=PIPE SIZE)	UPSTREAM CONFIGURATION
	‘CONCENTRIC REDUCER
	ELBOW
	TWO ELBOWS HORIZONTALLY
	TWO ELBOWS VERTICALLY

FIGURE 6-7. Minimum Straight Length Piping for Vortex Shedding Meters

8. MAINTENANCE . At least once a year vortex shedding meters should be Inspected for possible damage from dirty or viscous fluids. Check upstream filters and replace if necessary. Devices for sensing and transmitting pressure and temperature values to the flow processor should be inspected and calibrated at least once per year.

Section 3. ELECTROMAGNETIC FLOWMETERS

1. INTRODUCTION. Electromagnetic flowmeters (magmeters) can handle most liquids and slurries, including corrosives, providing that the material being metered is electrically conductive. Most industrial and municipal water and waste liquids can be measured by these meters. Liquids with suspended solids and certain waste flows which are often impossible to meter otherwise, are dependably measured with electromagnetic flowmeters.

1.1 Operating Principles. Electromagnetic flowmeters operate on Faraday's law of electromagnetic induction, which states that the voltage induced across a conductor, that moves at right angles through a magnetic field, is proportional *to* the velocity of that conductor. The liquid serves as the conductor; the magnetic field is created by energized coils outside the flow tube (Figure 6-8). The amount of voltage produced is directly proportional to the flow rate. Two electrodes mounted in the pipe wall detect the voltage, which is measured by the secondary element. Forward and reverse flow measurements are possible with no pressure drop.

2. METER DESIGNS. Electromagnetic flowmeters are available in full-bore and Insertion type configurations. Neither type has moving parts.

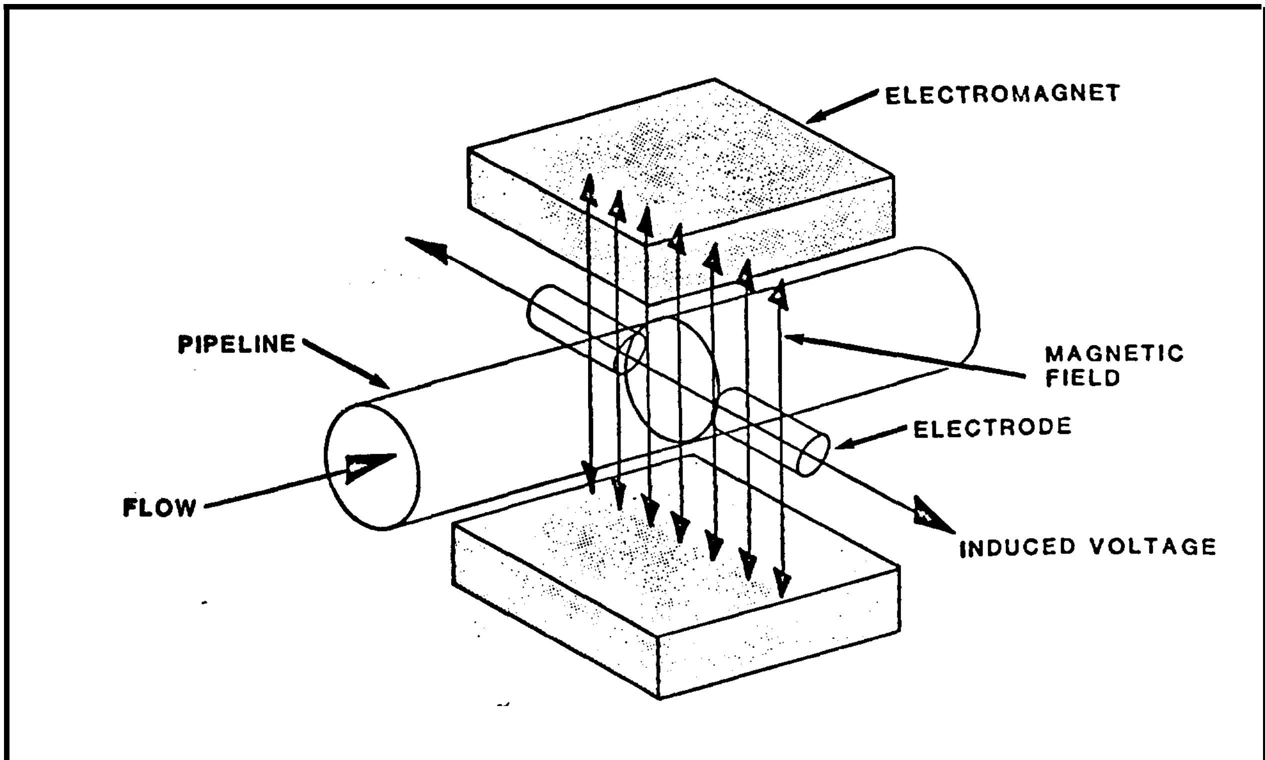


FIGURE 6-8. Electromagnetic Meter

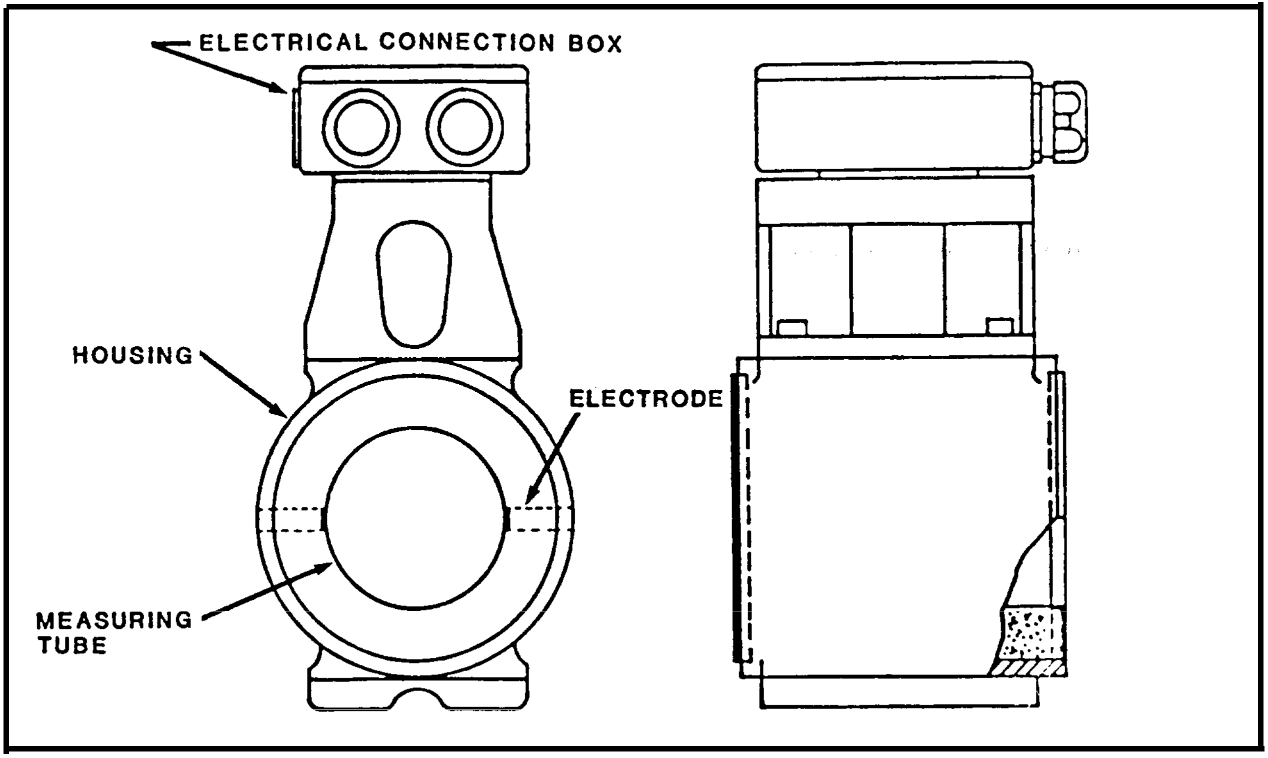


FIGURE 6-9. Full-Bore Electromagnetic Meter

2.1 Full-Bore Meters. The full-bore electromagnetic flowmeter (Figure 6-9) is an inline device with an inside diameter identical to the system. It is inserted between two flanges. These meters offer the same resistance to flow as a comparable length of pipe. The meter section of pipe is constructed of, or lined with, a nonmagnetic material. This prevents the metal tube from short-circuiting the conducting path of the induced magnetic field through the fluid from one electrode to the other. The electrodes for the liquid excitation are attached to, or implanted in, the pipe wall.

2.2 Insertion Meter. Insertion type electromagnetic flowmeters have the field-developing magnet and the electrodes for energizing the fluid combined in a single probe (Figure 6-10). The reduced size and weight make the installation simpler and maintenance cost lower.

3. RECOMMENDED APPLICATIONS. Electromagnetic flowmeters are available for liquid q easuring in pipe sizes greater than 0.1 inch. The flowmeters are recommended for measuring liquids of a conductive nature [a conductivity of 5 microsiemens (micromhos) per centimeter will meet the threshold requirements for most electromagnetic flowmeters]. Liquids may be clean, viscous, corrosive, or contain solids and may contain fibrous or abrasive material.

4. LIMITATIONS. Limitations that may preclude the use of an electromagnetic flowmeter for a specific purpose include the following:

l Temperature limit is 360°F (it is usually a consideration of the flow tube lining or the insulation of the magnetic coils).

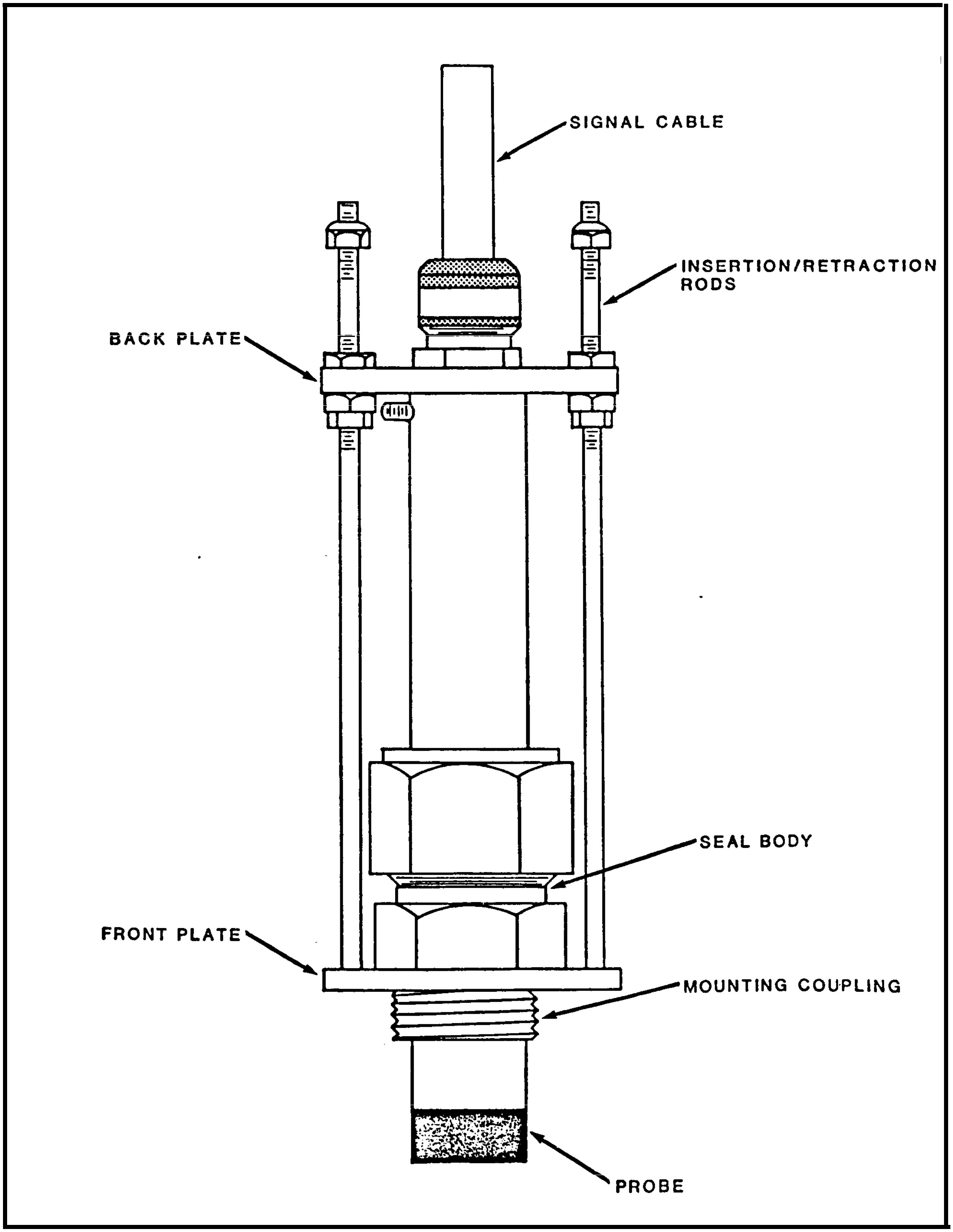


FIGURE 6-10. Insertion Electromagnetic Meter

- Pressure limit is commonly the same as the supporting system.

- Cost, initial and operational, may exceed project funding or negatively affect the project Savings-to-Investment Ratio (SIR).

- Flowmeter may require installation in a bypass line to avoid magnetic fields present in an existing pipe configuration.

- Data are inaccurate less than full-flowing pipe.

5. INSTALLATION. Both configurations of the electromagnetic flowmeter, full-bore type and insertion type, are discussed.

5.1 Full-Bore Meter Installation. The full-bore electromagnetic flowmeter inserts into a pipeline between two flanges and is secured with bolts. To obtain accurate measurements, the following conditions must exist:

- The meter is subject to electromagnetic fields and must be shielded from large electric motors, transformers, communications equipment, and other large electrical devices to avoid electromagnetic disturbances.

- The meter must be positioned so that the pipe is full flowing approaching and exiting the meter.

- The location of the full-bore electromagnetic flowmeter in the system is important. Whenever possible, it is preferable to locate the primary element in a horizontal line. To ensure accurate flow measurement, the fluid must enter the primary element with a fully developed velocity profile, free from swirls or vortices. Such a condition is best achieved by the use of adequate lengths of straight pipe, both preceding and following the primary element. The minimum recommended lengths of piping are shown in Figure 6-5. The diagram in Figure 6-5 that corresponds closest to the piping arrangement for the meter location should be used to determine the required lengths of straight pipe on the inlet and outlet. These lengths are necessary to limit piping configuration errors to less than ±0.5%.

5.1.1 Meter Grounding. A grounding system must be provided for the meter and the fluid. Detailed instructions for grounding systems are usually supplied by the equipment manufacturer. Some grounding considerations are as follows:

- For conductive piping, the third wire ground to the power supply and a ground tie to the piping flanges is typically all that is required.

- For nonconductive or lined piping systems, a protective grounding orifice must be used to provide access to the potential of the liquid being measured.

5.2 Insertion Meter Installation. Insertion electromagnetic flowmeters are available as hot tap or permanent types. Both types require installation of a tee or welded fitting on the pipeline for access. Insertion meters are generally restricted to lower temperature and pressure conditions. Installation of an insertion electromagnetic flowmeter requires consideration of the following items!

- The meter is subject to electromagnetic fields and must be shielded from large electric motors, transformers, communications equipment, and other large electrical devices to avoid electromagnetic disturbances.

- The meter must be positioned so that the pipe is full flowing approaching and exiting the ❑eter.

- Location of the insertion electromagnetic flowmeter in the system is important. Whenever possible, it is preferable to locate the primary element in a horizontal line. To ensure accurate flow measurement, fluid should enter the primary element with a fully developed velocity profile, free from swirls or vortices. Such a condition is best achieved by use of adequate lengths of straight pipe, both preceding and following the primary element. Minimum recommended lengths of piping are shown in Figure 6-5. The diagram in Figure 6-5 that corresponds closest to the piping arrangement for a ❑eter location should be used to determine required lengths of straight pipe on the inlet and outlet. These lengths are necessary to limit piping configuration errors to less than ±0.5%.

6. MINIMUM AND MAXIMUM FLOW RATES. Minimum and maximum flow rates must be established to maintain accurate flow measurements. Wear to the flow tube, buildup of coatings, and deposition of solids can be reduced if recommended flow rates are maintained.

6.1 Minimum Flow Rate. The minimum flow rate is usually determined by the rate that produces the lowest acceptable voltage requirement of the signal transmitted. If the minimum, rate causes excessive sedimentation, the diameter of the tube may have to be decreased to increase velocity through the meter. This provides a self-cleaning action.

6.2 Maximum Flow Rate. The maximum recommended flow rate is arbitrary, but is based on wear patterns experienced with different flow tube ❑aterials interfacing with a specific fluid. A maximum recommended flow rate of 30 feet per second is common.

7. ACCURACY AND RELIABILITY. Although it is possible to calibrate electromagnetic flowmeters to measure flow within +0.25%, a more representative accuracy is ±1.0% of its rated capacity. The downturn of electromagnetic flowmeters can be up to 40:1. If recommended maximum flow conditions are not exceeded (causing excessive flow tube lining wear), and hydraulic shocks (water hammer) are avoided, electromagnetic flowmeters are very reliable. Electrode corrosion greater than 0.002 inches per year is excessive and indicates a need for investigation to determine the cause.

8. **MAINTENANCE.** Since these are obstructionless instruments, the maintenance required is small. At least twice a year, remove and inspect the pressure sensors of the secondary element. Where there is a possibility of coatings accumulating, periodic cleaning is necessary because the coating will insulate the liquid from the electrodes and impair operation. All data transmission sensors and processors should be checked and diagnosed every six months for correct input and output.

Section 4. ULTRASONIC FLOWMETERS

1. **INTRODUCTION.** Ultrasonic flowmeters employ a basic principle of frequency shift (doppler effect) to measure flow rate of liquids. This type meter is totally exterior to the pipe, creates no pressure drop, and is not worn or damaged by liquids or slurries being measured. Being exterior, these flowmeters are constant in cost regardless of pipe size.

1.1 Operating Principles. Ultrasonic flowmeters use transducers to send and receive reflected signals from impurities in the flowing liquid measured. The signals are unaffected by temperature, density, or viscosity of the fluid.

2. **METER DESIGNS.** Ultrasonic flowmeters are divided into two groups, doppler effect and time-of-travel. Both designs provide accurate measurements for flow in either direction.

2.1 Doppler Meter. A doppler flowmeter measures frequency shifts caused by suspended particles in a flowing liquid. Two transducer elements are contained in a single transducer, a transmitting element and a receiving element. The transducer is potted in epoxy and inserted inside a fitting that has been welded to the pipe (Figure 6-11). A window cut in the pipe allows the transmitted signal of the transducer to enter the liquid, strike a particle, and be reflected back to the transducer. Solids, bubbles, or other

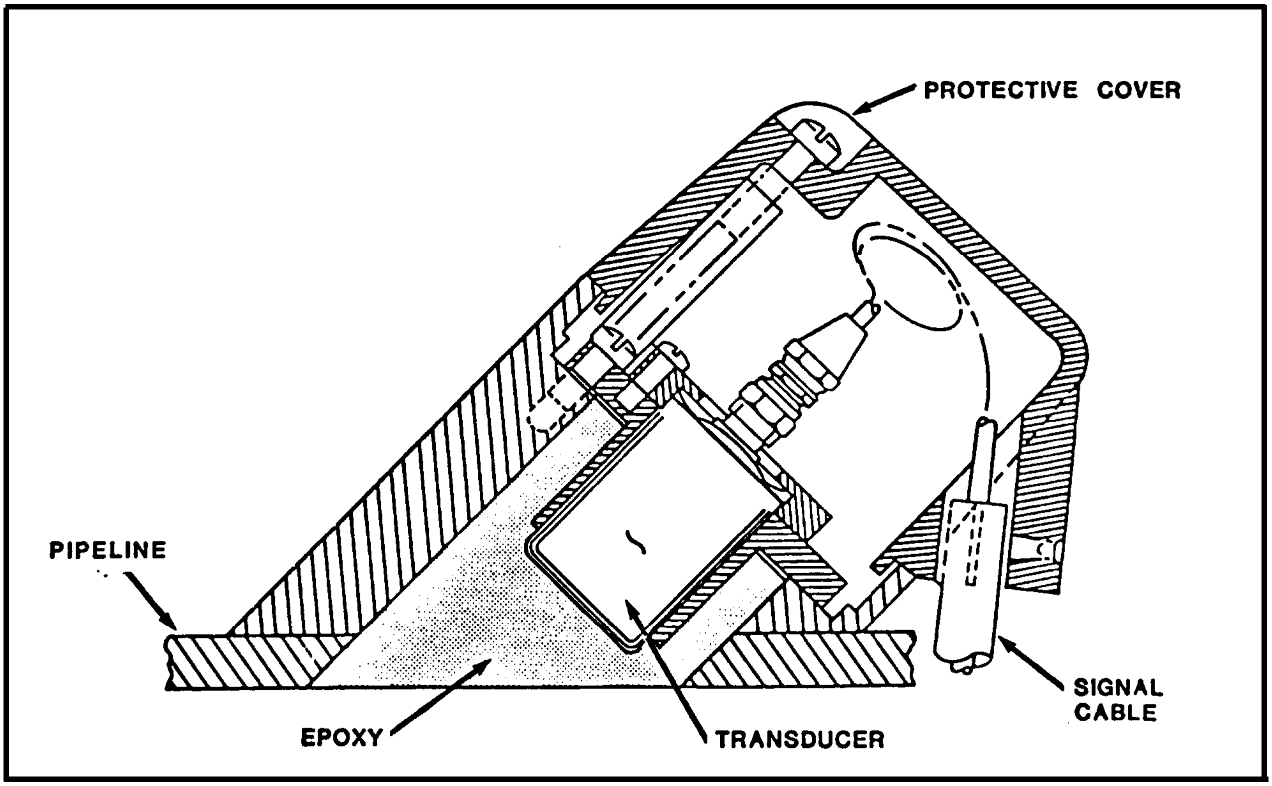


FIGURE 6-11. Doppler Ultrasonic Flowmeter

discontinuities in the liquid cause a signal pulse to be reflected to the receiver. Because the liquid (and entrained impurities that cause the reflection) is moving, the position of the particle that reflects the pulse changes at the flow rate. The change in location of the particle results in a shift in frequency of the reflected pulse. The frequency shift is proportional to the velocity of the liquid. Typically, the liquids being measured must contain at least 25 parts per million of 30 micron or larger suspended particles or bubbles.

2.2 Time-of-Travel Meter. Time-of-travel meters have transducers mounted on opposite sides of the pipe (Figure 6-12). The configuration provides for emitted ultrasonic pulse-traveling between the two transducers mounted at a 45° angle to the direction of flow. The speed of the pulses in the liquid is timed. The difference in time between pulse transmission and reception traveling upstream and the pulse traveling downstream is proportional to flow rate. Time-of-travel meters measure flow of liquids that are relatively free of entrained gas or solids. These meters cover the range of liquids with entrained gases or solids from approximately 5 parts per million to a density capability of doppler type meters. Time-of-travel meters are sensitive to pipe wall thickness. Therefore, Inaccuracies arise if scale has formed on the interior of the pipe.

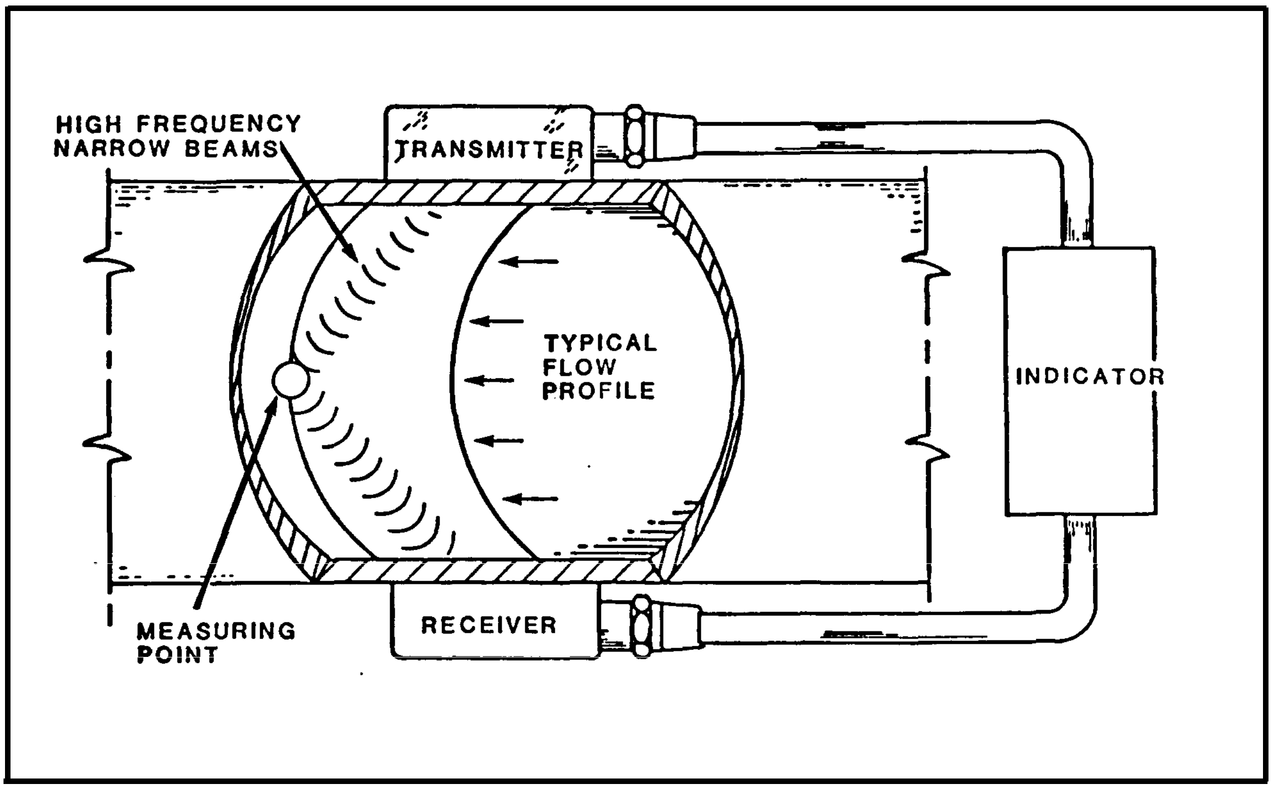


FIGURE 6-12. Time-of-Travel Ultrasonic Flowmeter

3. RECOMMENDED APPLICATIONS. A partial listing of recommended applications for ultrasonic flowmeters is as follows:

- Pipe sizes of l/2-inch and larger.
- Raw water, including wells, lakes, rivers, ponds, and springs.
- Water treatment plants including influent and effluent.

  Wastewater treatment plants including raw sewage, return and waste-activated sludge, secondary settling tank supernatant, treated effluent, plant water, tertiary treatment flows, and supernatant flows, except mixed liquor.

- Industrial flows including brine, plant effluent, and cooling water.

4. LIMITATIONS. Limitations of ultrasonic flowmeters are dictated by the degree of entrained solids and gases. One must know if the fluid contains solids or gases and at what concentration. Other limitations are as follows:

- Time-of-travel type requires clean liquids.
- Doppler type is best suited to unclean liquids.
- Excess solids in slurries may block ultrasonic signals.
- Cannot be used on asbestos or cement pipes.
- Pressure rating generally equal to piping system.
- Temperature range for time-of-travel type is -450°F to +500°F.
- Temperature range for the doppler type is -450°F to +250°F.
- Outside of pipe must be clean where meter is attached.
- Inside of pipe must be free of scale, rust, and corrosion.

5. INSTALLATION. A necessary requirement of installing electromagnetic flowmeters is that the pipe must be clean and free from rust on the outside end without scale or corrosion on the inside. In the preliminary evaluation of matching a meter to a system, the following considerations should be included.

5.1 Meter Choice. The major difference between the two types of ultrasonic flowmeters is their ability to measure liquids containing different levels of entrained impurities. The time-of-travel type is designed for clean liquids while the doppler type will measure dirty, corrosive, and slurried liquids.

5.2 Meter Position. The meter must be positioned so that pipe approaching and exiting the meter are full of process fluid under all operating conditions.

5.3 Meter Location. Location of the ultrasonic flowmeter in the system is important. Whenever possible, it is preferable to locate the primary element in a horizontal line. To ensure accurate flow measurement, fluid should enter the primary element with a fully developed velocity profile, free from swirls or vortices. Such a condition is best achieved by use of adequate lengths of straight pipe, both preceding and following the primary element. The minimum recommended lengths of piping are shown in Figure 6-5. The diagram in Figure 6-5 that corresponds closest to the piping arrangement for the meter location should be used to determine required lengths of straight pipe on the inlet and outlet. These lengths are necessary to limit piping configuration errors to less than ±0.5%. If minimum distances are not observed, flow equations and resultant flow calculations may produce inaccurate data.

6. ACCURACY AND RELIABILITY. Both types of ultrasonic flowmeters have an accuracy of +5.0% of the upper range value. New electronics and more efficient designs have improved meter reliability. Ultrasonic flowmeters are available with self-diagnosing features that include the following:

- Applications.
- Transducer malfunctions.
- Cable and circuit failures.

7. MAINTENANCE . Maintenance on these obstructionless instruments is small. At least twice a year, remove and inspect the pressure sensors of the secondary element. Where there is a possibility of coatings accumulating, periodic cleaning is necessary because the coating will cause refraction angles to change. Also, sonic energy is absorbed by the coatings and renders the meter inoperative. Data transmission sensors and processors should be checked and diagnosed every six months for correct input and output.

CHAPTER 7. OPEN CHANNEL METERS

Section 1. WEIRS

1. INTRODUCTION. Weirs are used in open channels and in conduits where the fluid has a free surface, such as canals, streams, rivers, tunnels, nonpressurized sewers, and partially filled pipes.

1.1 Meter Designs. Weir designs are classed as sharp crested and not sharp crested. Sharp crested weirs are used for flow measurement. Not sharp crested weirs are used for flow control and are not discussed in this manual.

1.1.1 Sharp-Crested Weirs. Sharp-crested weirs (Figure 7-1) are classified according to the form of the notch or opening as follows:

- Rectangular notch, original form.

- V-notch, used to provide higher head readings at low flow rates.

- Trapezoidal, hyperbolic, and parabolic, special notch types, intended to have a constant discharge coefficient or to have a head directly proportional to the flow rate.

1.1.2 Broad-Crested Weirs. Broad-crested weirs have a considerable thickness of crest as measured along, and parallel to, the channel. The crest should be thick enough to prevent the nappe from springing free at the upstream edge (Figure 7-2). This requires a thickness equal to at least twice the maximum head if the upstream edge of the crest is square. Thickness of the crest may be reduced one-fourth if the upstream edge is rounded.

1.1.3 Round-Crested Weirs. The curvature of the crest surface of a round-crested weir may be radial or some other geometric curve such as a parabola (Figure 7-3). The upstream face of these weirs may be vertical or sloping. Both the degree of the crest rounding and the amount of slope to the faces affect the rate of discharge. Weirs of this type are seldom built with the primary purpose of measurement.

1.2 Operating Principles. A weir is a dam-like device that obstructs liquid flow and creates a controlled nappe and head of liquid which can be measured. For flow measurement, the weir is considered a primary device to be used in conjunction with a level measuring device.

2. LIMITATIONS. The basic limitations of a weir type open channel flowmeter are as follows:

- Conditions must be present to provide for development of a head of liquid .

- Weirs are not recommended for flows that contain large amounts of suspended solids or debris which could accumulate to Impede flow.

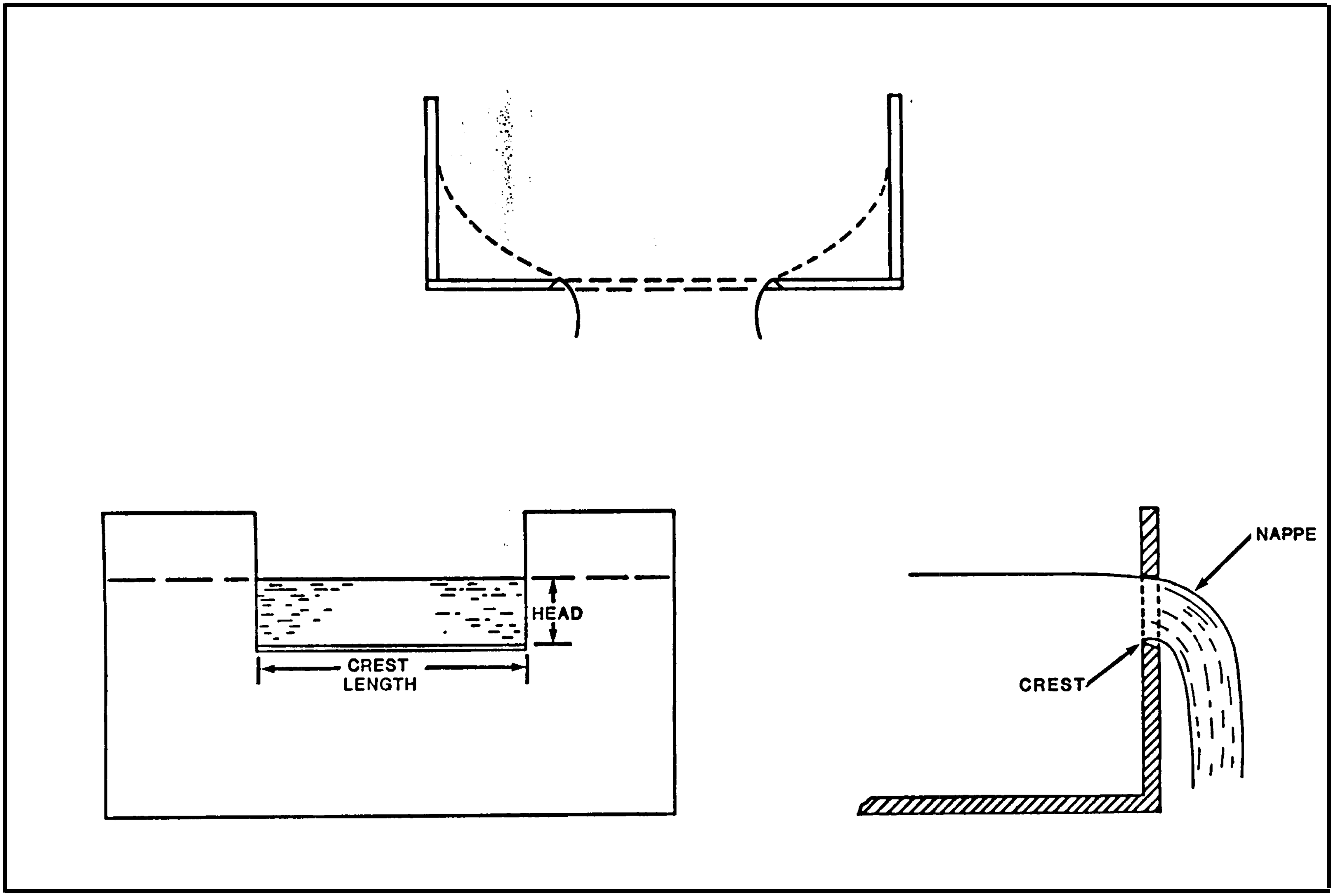


FIGURE 7-1. Sharp-Crested Weir

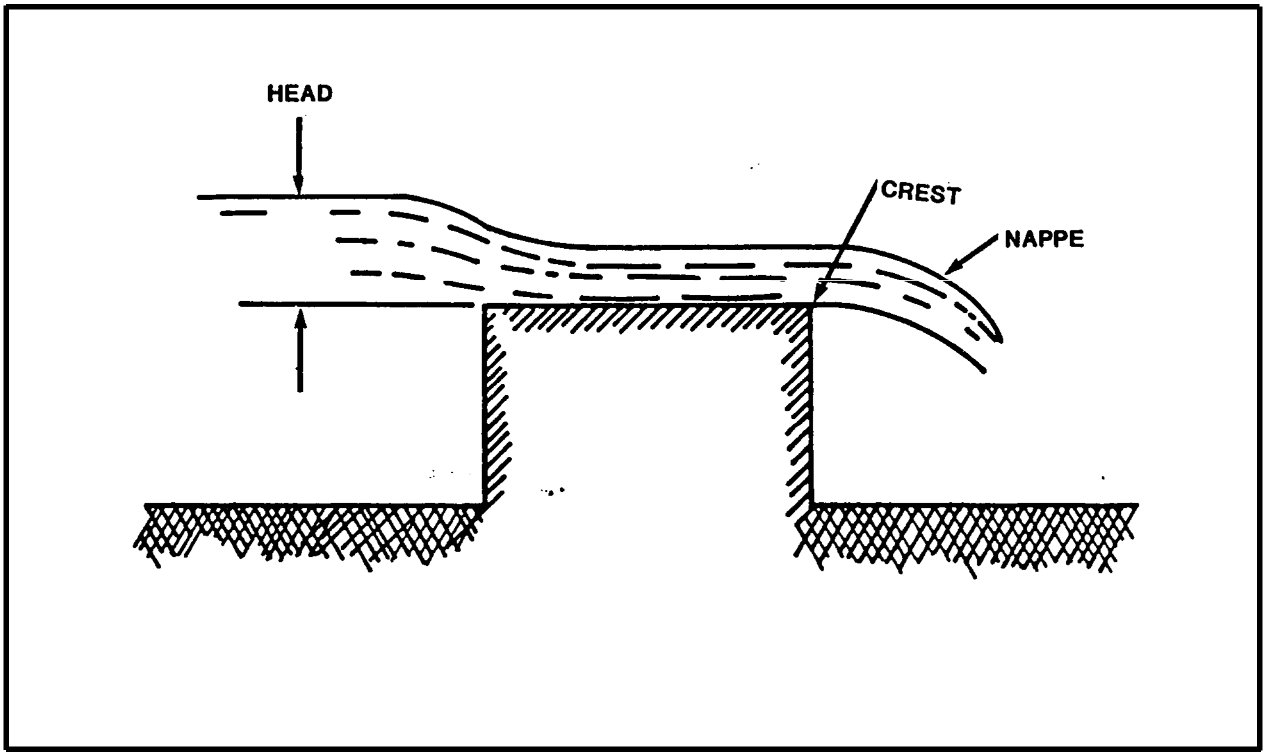


FIGURE 7-2. Broad-Crested Weir

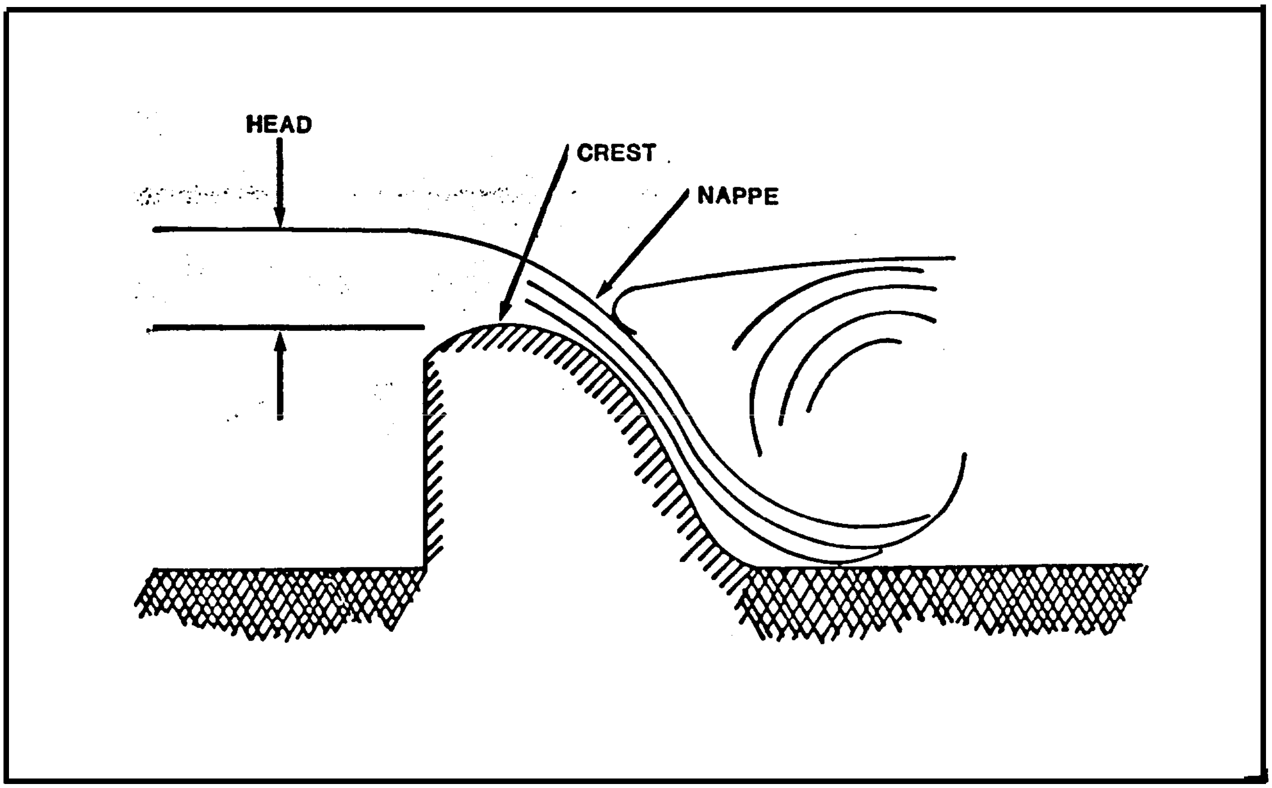


FIGURE 7-3. Round-Crested Weir

3. INSTALLATION. To obtain reliable flow information, weir installation must include sufficient upstream and downstream preparation. The following paragraphs are general suggestions only. A design engineer is required to provide specific details.

3.1 Upstream. A weir should be preceded by a straight uniform section of channel to ensure uniform velocity distribution in the flow. The length of this channel should be 4 to 6 times the width of the approach channel upstream of the weir.

3.2 Downstream. On the downstream side of a weir plate, the edges of the channel end wall, to which the plate is mounted, should be cut away so that the nappe will fall freely without adhering to the end wall. Also, the width of the downstream channel at the weir should be sufficiently greater than the crest length, so that the sides of the nappe fall free.

4. MAINTENANCE. All types of head and area meters are used for open flow measurement, and their operation depends on the absence of any kind of interference at the discharge opening. Weirs require the following maintenance procedures.

4.1 Daily Maintenance. Check the weir edge daily to make sure it is clean and free of algae growth and other interfering material.

4.2 Monthly Maintenance. Make sure the breather pipe is open. In cold weather make sure frost is not blocking the opening.

4.3 Annual Maintenance. Drain the weir and make sure that water breaks evenly over the crest. Check the weir edge for irregularities and correct if found.

5. ACCURACY AND RELIABILITY. The accuracy of flow measurements made with sharp-crested weirs varies depending upon the sharpness of the weir edge, the exactness with which the weir dimensions were determined, and the method and accuracy of head determination. Weir accuracy is determined to vary between 0.5 and 4.0 percent. The reliability of weirs is not a quantitative characteristic since the crest must be free of debris to function correctly.

Section 2. FLUMES

1. **INTRODUCTION.** A flume in an open or closed conduit is similar to a venturi in a fully charged pipeline. The channel is constructed to cause a decrease in pressure and an increase in velocity. A common characteristic of flumes is the formation of a standing wave close to the outlet of the constricted section which is why they are sometimes called standing wave flumes. There is no "standard" flume; each is individually designed.

1.1 Meter Designs. The Parshall flume and the Palmer-Bowlus flume are two designs currently in common use.

2. **OPERATING PRINCIPLES.** In flumes, the measuring section can be designed with a contraction of the sidewalls, by a raised section, or hump, of the channel bed, or by a combination of both contraction and hump. These changes cause a measurable difference in head pressure between the converging section and the throat. The difference in these pressures is used to calculate flow rate.

2.1 Parshall Flume. The Parshall flume is a measuring flume that is well-adapted to use in irrigation canals and ditches. This flume consists of an entrance section with converging walls and level floor, a throat section with parallel walls and a downstream sloping floor, and an outlet section with diverging walls and rising floor (Figure-7-4). The crest is the line where

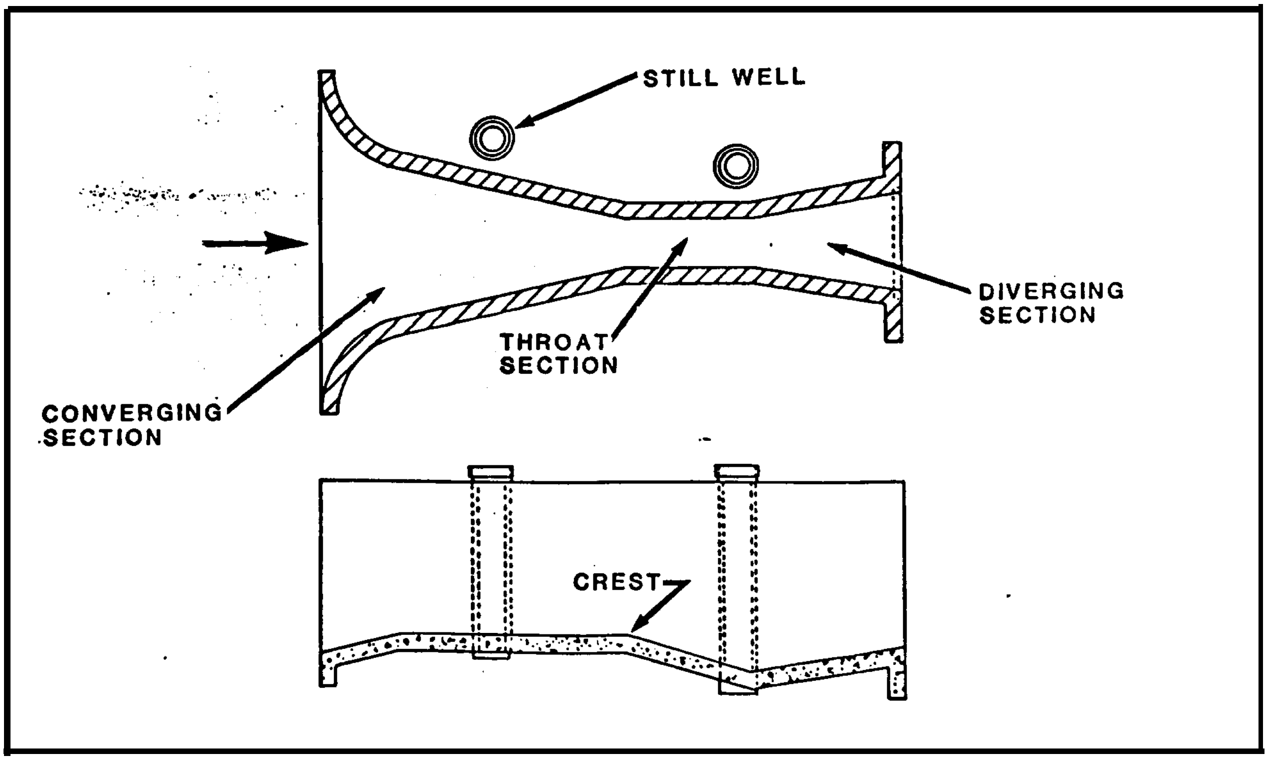


FIGURE 7-4. Parshall Flume

the level floor of the converging entrance section joins the inclined floor of the throat section. Still wells may be installed alongside a flume to view water level if flume surface is frozen over or water surface is thick with debris.

2.2 Palmer-Bowlus Flume. The Palmer-Bowlus flume is used primarily in circular conduits such as storm and sanitary sewers. Both sidewall and bottom contraction are used (Figure 7-5).

3. LIMITATIONS. The major limitation of flumes is that they are designed for individual locations, such as general information metering of storm and sanitary sewers or irrigation purposes.

4. INSTALLATION. Since flumes are not off-the-shelf meters, installation is governed by design. Upstream and downstream cross-sections and lengths are in the design specifications for each location. Follow design specifications for grade height and zeroing of still wells, if used.

5. MAINTENANCE. All types of head and area meters are used for open flow measurement. Their operation depends on the absence of interference at the discharge opening.

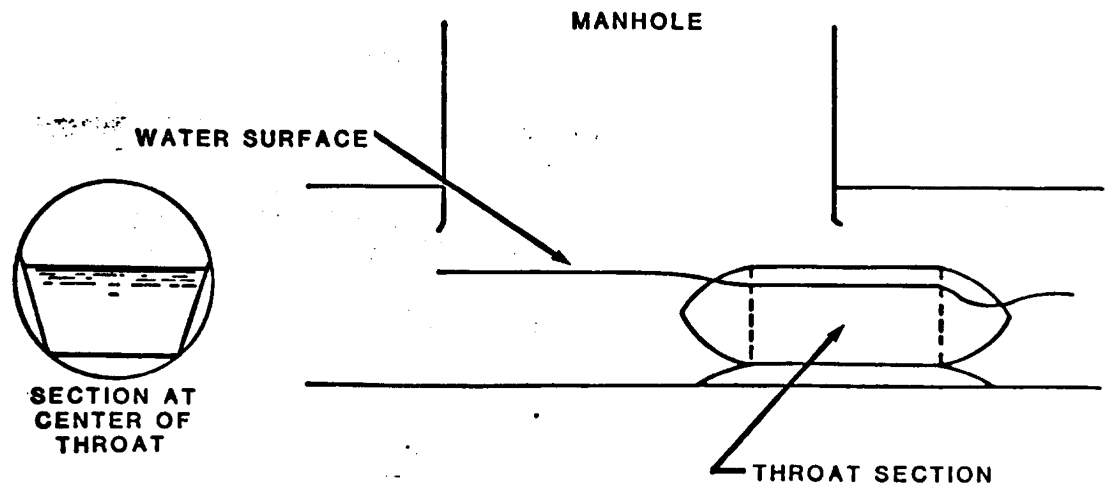


FIGURE 7-5. Palmer-Bowlus Flume

5.1 Monthly Maintenance. Make sure the throat section is unobstructed and clean. Remove algae growth.

5.2 Quarterly Maintenance. Clean the stilling well and make sure connecting pipe is clear.

6. ACCURACY AND RELIABILITY. Accuracy of the Palmer-Bowlus flume is +3%; this error coupled with the level measuring device error gives a combined accuracy of approximately ±10%. The reliability of flumes is *not* a quantitative characteristic since it must be kept free of debris to function correctly. Flumes are less accurate than a weir.

Section 3. LEVEL MEASURING DEVICES

1. **INTRODUCTION.** To maintain accuracy obtained by a primary device, a flowmeter must measure fluid level at the measuring point and precisely convert it to flow rate. This entails choosing a level measuring device appropriate for site conditions.

1.1 Operating Principles. Level measuring devices operate using either the time for sonic echo response from surface to bottom of liquid flow or differences in atmospheric pressure between surface and bottom of liquid flow. The application of these principles is described in various meter designs.

2. **METER DESIGNS.** Each of the meter types discussed are available with the capability to integrate flow level data with preprogrammed data specific to the site and provide an accurate flow rate.

2.1 Ultrasonic Level Meters. This type of level meter incorporates timing of ultrasonic pulses and echoes to determine liquid level. A sensor/transducer is fixed above the surface and is unaffected by the type of liquid (Figure 7-6). The transducer emits a signal directed at the surface of the liquid and measures the time interval of echo response.

2.2 Bubble Type Meter. The sensing probe for this type of meter is mounted below the surface of the liquid (usually at the bottom) (Figure 7-7). The

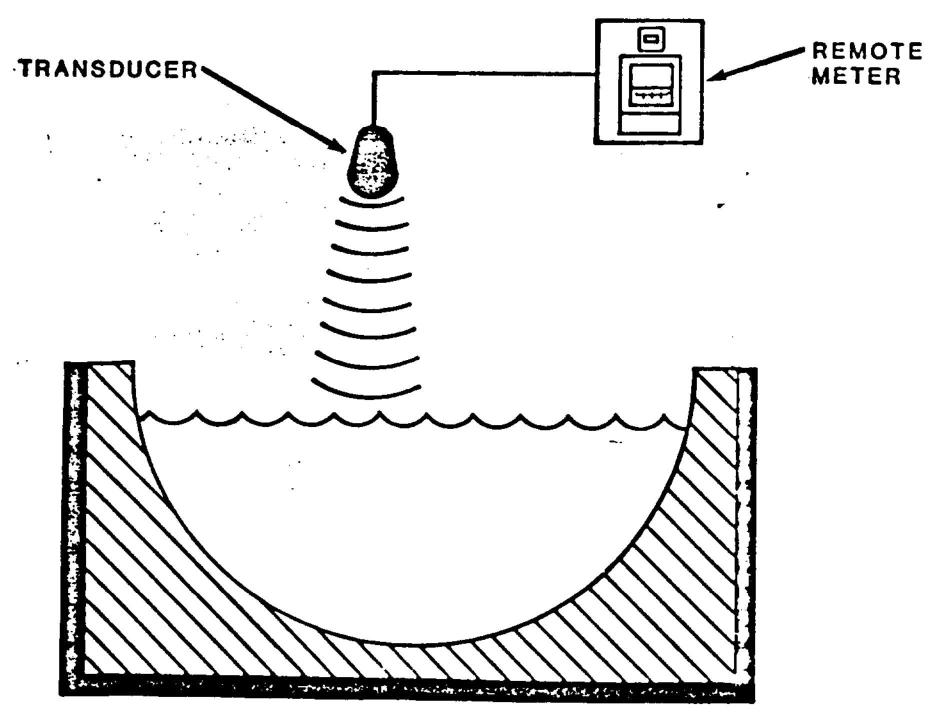


FIGURE 7-6. Ultrasonic Level Meter

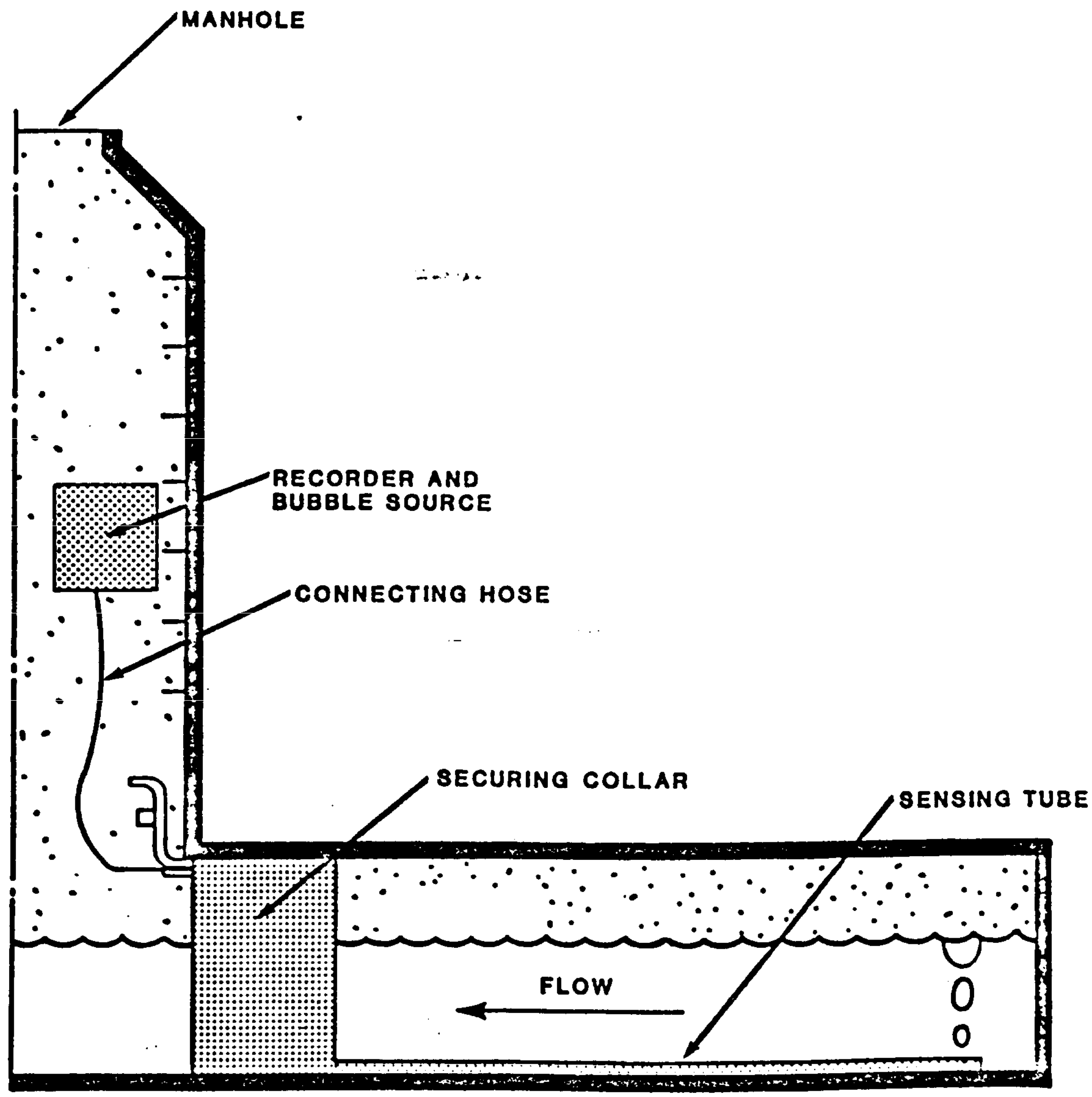


FIGURE 7-7. Bubble Level Meter

probe contains a pressure sensitive transducer and a tube for releasing gas for bubble formation. The sensor measures pressure required to produce bubbles. The relationship that exists between bubble pressure and head provide data to determine flow rate.

2.3 Submerged Probe. The submerged probe type level meter is a differential pressure transducer that relates pressure created by the liquid head to atmospheric pressure (Figure 7-8).

2.4 Meter Selection. Table 7-1 illustrates typical site conditions and possible meter applications and requirements.

3. LIMITATIONS. Level measuring devices have the following limitations:

- Must have access such as manhole or handhole for installation.
- Must have electrical power source.
- Must have compressed air source.
- Does not have provisions for digital data transmission and recording.

4. INSTALLATION. Installation of the flow channel is permanent at most sites. The flow metering device is available as a portable or permanent type. There is little difference in installation of the two types.

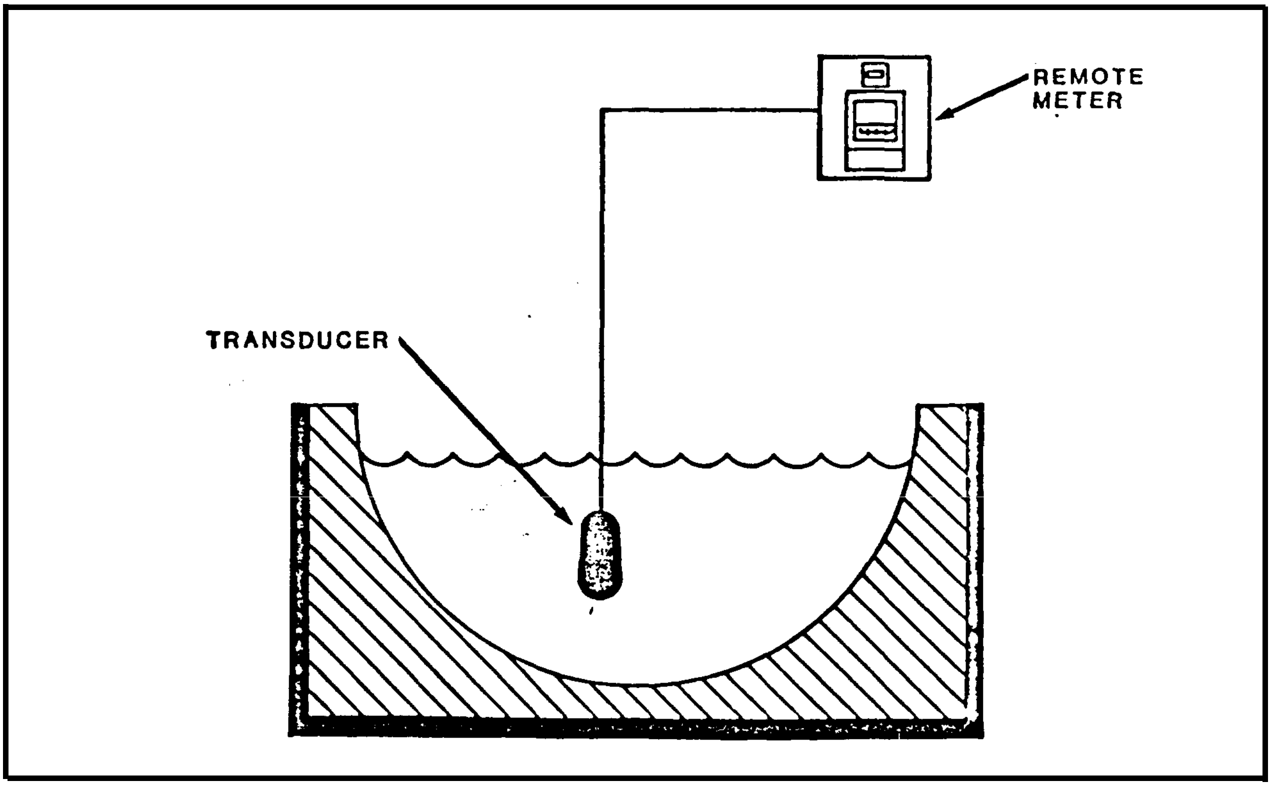


FIGURE 7-8. Submerged Probe Level Meter

TABLE 7-1. Level Meter Selection Guide

Application Requirements and Site Conditions	Bubbler	Submerged Probe	Ultrasonic
Factors Affecting Accuracy	**Performance**		
Silting in	Use with caution	Very good*	Excellent
High crosswinds	Excellent	Excellent	Not recommended
Floating debris	Excellent	Ecellent	Poor
Suspended solids (high concentration)	Not recommended	Very good*	Ecellent
High grease concentration	Not recommended	Very good*	Excellent
Foam on liquid	Excellent	Excellent	Not recommended
Narrow channel	Excellent	Excellent	Use with caution
Factors Necessitating Onsite Maintenance	**Maintenance Required**		
Silting in	Often	None to occasional*	None
Suspended solids	Often	None to occasional*	None
High grease concentration	Often	occasional*	None
Channel Application	**Installation**		
Weirs and flumes	Very easy	Very easy	Easy
Small round pipes	Moderately easy	Very easy	Easy
Large round pipes with swift current	Difficult	Difficult	Easy
Irrigation channel or small stream	Somewhat difficult	Somewhat difficult	Easy
River or other large stream	Difficult	Difficult	Easy (if structure over stream exists)

*Probes are only affected by a mixture of grease and solids.

5. **MAINTENANCE.** Level measuring devices require inspection and calibration every six months. For mechanical devices, ensure that all moving parts work freely and correctly. For electronic devices, check sensors and processing equipment for calibration. All devices require periodic viewing to ensure that material has not accumulated on or damaged the device resulting in erroneous or no data.

6. **ACCURACY AND RELIABILITY.** Level-sensing devices differ in the method of operation, but accuracies of ±1.0% and repeatabilities of ±0.1% can be expected. Since level-sensing devices are accurate to ±1.0%, the developed relationship between flow level and channel becomes the area of least accuracy in the system. Combining the two devices produces a probable accuracy range of ±1.0 to ±8.0%. Reliability of these systems is very good, if basic maintenance is performed.

Section 4. VELOCITY MODIFIED FLOWMETERS

1. **INTRODUCTION.** A velocity modified flowmeter is a single-unit sensing device utilizing velocity, depth, and diameter data to determine volumetric flow in open channels. Special units can be obtained for use in full pipe flows. A typical unit is made up of a steel band to which is attached an electromagnetic flow-velocity sensor and a pressure transducer to measure water depth (Figure 7-9).

1.1 Operating Principles. Using a plug-in module correlated to the pipe diameter, the processor applies velocity and depth data to the continuity equation ($Q = A \times V$) and computes volumetric flow without need for pipe slope, surface roughness, or empirical formulas. Even though volumetric flow is the principle information computed and recorded, velocity and depth data may be displayed.

2. **METER DESIGNS.** A typical unit is a steel band, sensor units, and cabling between the power source and the data transmitter.

2.1 Steel Band. An expandable, stainless steel band recessed into the flow conduit and expanded against the interior wall. Attached to the steel band is a capsule containing the velocity and depth sensors. The capsule shape is streamlined to prevent fouling of debris.

2.2 Velocity Sensor. A solid state, electromagnetic sensor attached to the steel band to correlate existing velocities to mean velocity of the flow conduit. These data are transmitted to the unit processor.

2.3 Depth Sensor. Water depth is measured by a submerged pressure transducer encapsulated with the velocity sensor. Water depth data are transmitted to the unit processor.

3. **LIMITATIONS.** The limitations of a typical velocity modified flowmeter are as follows:

- Conduit diameter range is from 8 to 102 inches.
- Temperature limits are from -l°C (-30°F) to +32°C (+90°F).
- Liquids must have a conductivity of at least 5 micromhos/cm.
- Diameter of pipe or cross-section of channel must be known.
- 120 VAC, 60 Hz power is required.

4. **INSTALLATION.** Velocity modified flowmeters are installed inside pipes using an expandable steel band sized to the pipe diameter. Velocity and depth sensors are an integral part of the band. Cabling is attached to the sensors from a power supply and to recording equipment. Installation ❑ay be permanent or temporary.

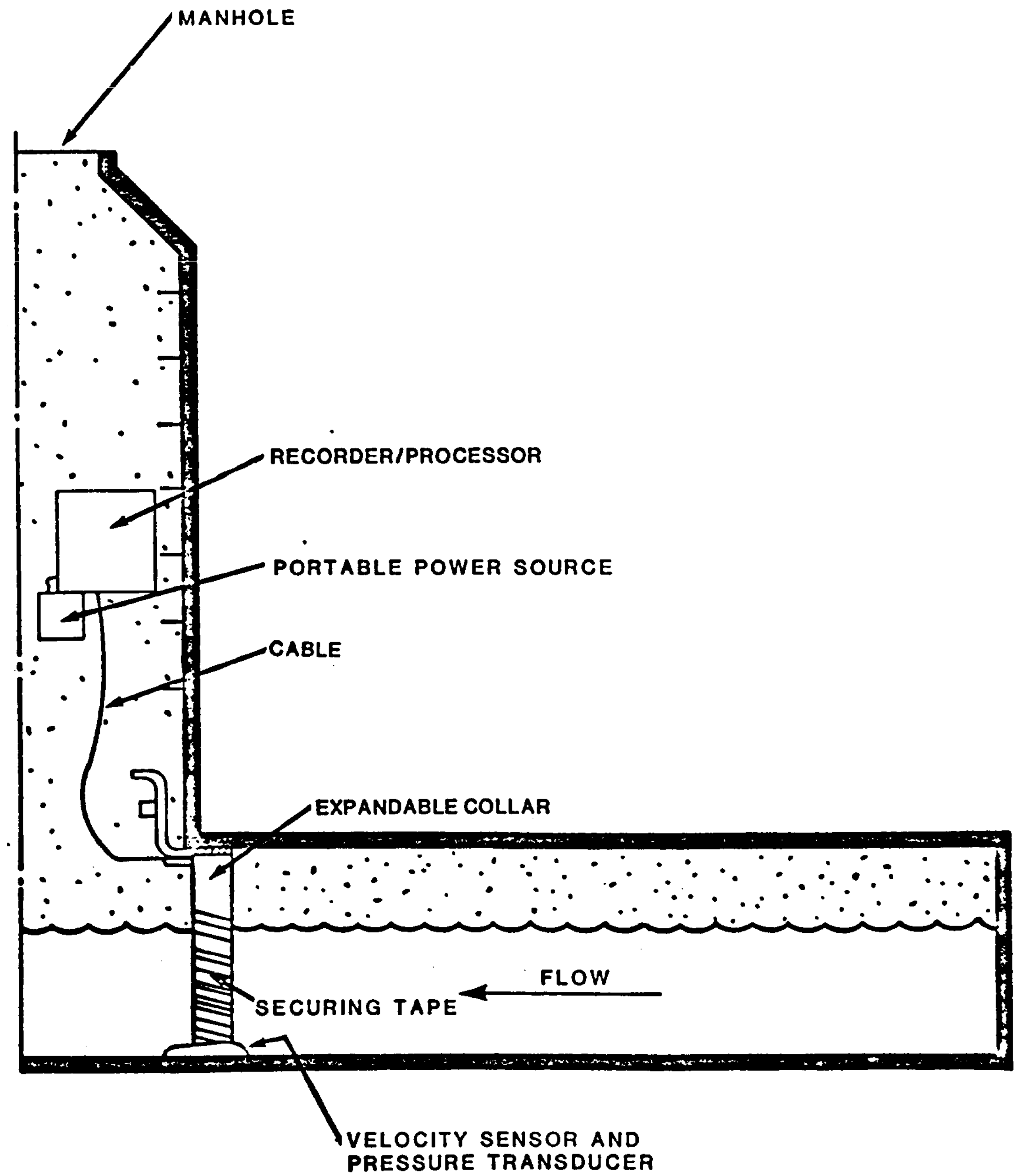


FIGURE 7-9. Velocity Modified Flowmeter

5. MAINTENANCE. Inspect every six months to ensure sensors, recording and processing equipment are calibrated and functioning.

6. ACCURACY AND RELIABILITY. Typical accuracy of a velocity modified flowmeter is ±2% with a repeatability of ±0.5%. Reliability is high as long as scheduled maintenance is performed.

CHAPTER 8. SURVEYING THERMAL FLUID DISTRIBUTION SYSTEMS

1. INTRODUCTION. Fuel usage records are often the only reliable source for estimating the consumption of energy used by a thermal fluid distribution system and the processes served by that system. This accounting process does not provide knowledge of when and where energy is consumed or how efficiently it is produced. Properly selected flowmeters, which provide time-based consumption patterns are required to successfully survey and manage a thermal fluid distribution system.

1.1 Plant Level Meters. Accurate metering of fuel, feedwater, condensate, and steam or high temperature water produced and exported is required to manage a boiler plant. This level of metering provides boiler efficiencies and overall plant input/output efficiencies. Also, superheaters and desuperheaters can be monitored and more efficiently operated. Export meters provide overall consumption of energy used by the customers, including system losses. Peak energy usage and time of day usage are quantified and analyzed.

1.2 Trunkline Meters. Trunkline meters are installed in the main distribution system to determine energy use by distinct areas of a facility. Where possible, areas should be defined by specific customer to achieve greater accountability. Usage profiles from trunkline meters can determine where, when, and how efficiently energy is used. Unusually large system losses may also be identified. An optimum distribution configuration is determined based on energy demand profiles. Trunkline metering also provides pressure drop analyses for a system.

1.3 Portable Meters. Portable meters are installed and removed without interrupting service. Individual process or building loads are profiled for troubleshooting or planning and design purposes. Line loss tests are done using portable meters. Caution must be taken if using two meters for line loss tests. The loss measured may be below the accuracy of the meters. Economic analyses of energy conservation projects are more accurate with the use of data from portable meters.

1.4 Condensate Meters. Condensate meters can be used to infer steam loads by quantifying the amount of condensate returning to the steam plant. Condensate meters are lower cost than steam meters, they do not require pressure or temperature compensation, they are generally more reliable than steam meters, and they require less maintenance. However, condensate meters should be used with caution, since steam may be consumed in processes or lost through leaks or steam traps. Additionally, if the condensate return system is in poor condition, a significant portion of the total condensate may be lost through leaks. Consequently, the amount of condensate measured may be significantly less than the amount of steam actually used.

2. METERING PROGRAM. A successful metering program requires the following:

a. Specification and installation of meter systems.

b. Scheduled maintenance and calibration of meter systems.

c. Scheduled collection, reduction, and analysis of data.

d. Management support of the metering program.

CHAPTER 9. ELECTRIC METERING

Section 1. REQUIREMENTS AND USE

1. **INTRODUCTION.** Metering electrical energy involves use of many types of meters and associated devices. In many cases, totalizing of kilowatthour (kWh) usage during a time interval is adequate for studies and billing purposes. Many more parameters of electric power can be measured to provide insight into electrical demand requirements. Some parameters measured to complete a more accurate and informative analysis of an electrical system are as follows:

- Voltage
- Ampere
- Phase angle
- Kilowatt
- Kilowatthour
- Onpeak kW demand
- Mid-peak kW demand
- Offpeak kW demand
- Time-of-use
- Power factor
- Real power
- Apparent power

2. **IMPORTANCE OF METERING.** Metering electrical energy serves three important purposes: provides energy audit data, identifies distribution of costs to users, and sets standards to be used to evaluate performance. Meter installation can be costly, but the return in savings usually is worth the investment. Based on data from 1980, the cost of installing a kilowatthour meter ranges between $300 and $1,000.

2.1 Audits. To obtain useful information for an audit, a survey requires a metering system and a formally standardized method of collecting and reducing data. Percentages of energy efficiency and pinpointing inefficient equipment are results that an audit will produce. An energy profile will do the following:

- Aid in establishing and refining energy use by department or area.
- Establish and improve accountability.
- Measure cost reductions.
- Determine equipment capabilities and load factors.
- Help in planning facility modifications and expansions.
- Provide data to analyze variance from standards.
- Identify successful energy management projects.

2.2 Accurate Charges. Accurate distribution of charges to energy users is needed. Contrary to limited metering of the past, sufficient and discriminate

placement of meters today allows the identification and charging of individual users. Items to take into consideration when planning for metering system are:

- Sufficient money to monitor the desired number of circuits.
- Staff with time and qualifications to read meters.
- Placement of conductors for efficient connection to potential and current transformers.
- Loads that cannot be shut down for meter installation.
- Placement of meters for easy access in safe locations.
- Design engineers knowledgeable in metering system requirements.
- Training of maintenance personnel.
- Funding for maintenance and spare parts.
- Cross reference method to determine need for meter calibration.

2.3 Standards. Energy consumption standards can be developed from historical data. Once a standard has been set, periodic monitoring and plotting may reveal a variance that requires further investigation.

Section 2. CONCEPTS OF METERING ELECTRICITY

1. **INTRODUCTION.** To effectively manage or participate in electric energy management programs, a basic knowledge of electricity and meters is highly beneficial. A course in electricity and meters is beyond the scope of this manual. The material presented here acquaints individuals with fundamental electrical units and phenomena specifically related to meters. The major emphasis is to show how information obtained from electrical meters is applicable to management programs. There is some mathematical and technical discussion, but it has been kept to a basic level.

2. **COMMON METERING TERMS.** The following definitions provide the means for a basic application of metering data.

Ampere (I): Unit of current or rate of flow of electricity.

Blondel's Theorem: The power/energy in a circuit of N lines can be metered by N single-phase watt/watthour meters with the potential circuits connected from each line to any common point. If the common point is on one of the lines, the power/energy can be metered by N-1 watt/watthour meters.

Demand Analysis: Demand analysis is the critical examination of demand profiles obtained from a power survey recorder (PSR), or compiled from data collected using kilowatthour meters, rate schedules, demand registers, and other instruments. One of its purposes is to locate peaks and valleys in a demand profile to evaluate the possibility of load shifting to level out the profile and to reduce demand charges.

Demand Factor: Ratio of maximum demand to the total connected load.

Demand Peaks: Although demand billing procedures are not uniform, time-dependent demand charges are typical. One method uses onpeak, midpeak, and offpeak hours to assess demand charges. Although hours may vary between summer and winter months, a typical summer schedule is: onpeak-demand--1:00 PM to 7:00 PM, weekdays; midpeak-demand--9:00AM to 1:00 PM and 7:00 PM to 11:00 PM, weekdays; offpeak-demand--all other hours including holidays. Highest charges are assessed for onpeak-demand with proportional cost reductions for midpeak and offpeak periods.

Demand Profile: A demand profile is a graphic representation of electrical demand made on a system during a given period. The profile illustrates the relationship between demand, in kilowatt, and time of day demand occurred. When graphing, place demand on y-axis and time on x-axis.

Diversity Factor: Ratio of the sum of individual maximum demands of various subdivisions of a system to the maximum demand of the whole system.

Horsepower (hp): Measure of time rate of doing work; equivalent to raising 33,000 lbs, one ft in one minute; 746 watts.

Hours-Midpeak: This is time-of-day charge used by some utilities in demand or total energy billing. Midpeak-hour demand charges are often considerably less than onpeak-hour demand charges. Total energy charges my average 15 to 20 percent less than onpeak-hour charges. Although the schedule will vary among utilities, a typical summer schedule for midpeak-hours is from 9:00 AM to 1:00 PM and 7:00 PM to 11:00 PM on weekdays.

Hours-Offpeak: This is a time-of-day charge used by some utilities in demand or total energy billing. Use of electricity during offpeak-hours results in lowest total energy charges and in some instances may not result in a demand charge. Although schedules will vary, a typical summer offpeak-hours schedule is all holidays, Saturdays, Sundays, and from the hours of 11:00 PM to 9:00 AM on weekdays.

Hours-Onpeak: This is a time-of-day charge used by some utilities in demand or total energy billing. Use of electricity during onpeak-hours results in the highest charges for demand or total energy use. Although hours may vary among utilities and will vary between summer and winter, a typical summer schedule for onpeak-hours demand is from 1:00 PM to 7:00 PM on weekdays.

Kilovolt Amperes (kVA): 1,000 volt-amperes.

Kilowatt (kW): 1,000 watts.

Kilowatthour (kWh): 1,000 watthours.

Load Factor: Ratio of average load over a designated period of time to peak load occurring in that period.

Load Shedding: Load shedding is shutting down electrical loads to reduce total load and to lower demand.

Megohm: 1,000,000 ohms.

Ohm (R): unit of resistance.

Ohm's Law: $I = \frac{E}{R}$ (cd or 100% pf)

Phase Angle: The phase angle refers to the angle created between the sinusoidal voltage curve and either a lagging or leading current curve. Although current may either lag or lead voltage, commercial users try to ensure current is slightly lagging.

Power Factor: Power factor (pf) is a ratio of real power measured in watts of an alternating current circuit, to apparent power measured in voltamperes. Power factor is also the cosine of the phase angle between the voltage and current.

$$pf = \frac{W}{VA} = \frac{kW}{kVA} = \cos(\theta) \text{ of power triangle}$$

Power-Apparent: Apparent power is the product of voltage and current in a circuit in which voltage and current reach their peaks at different times. In other words, there is a phase angle between the voltage and current. Apparent power is measured in volt-amperes.

Power-Reactive: Reactive power, also called wattless power, is q easured in terms of voltampere-reactive (VAR). Reactive power increases as power factor decreases and is the component of apparent power that does no real work in the system.

Power-Real: Real power is the component of apparent power that represents true work in an alternating current circuit. It is expressed in watts and is equal to apparent power times power factor.

Signal-Analog: An analog signal is a voltage or current signal that is a continuous function of the measured parameter. Analog signals provide direct, instantaneous information. It is most often used for onsite monitoring with meters and pen chart recorders. If analog signals are to be transmitted over long distances, the signal is generally converted into a numerical value before transmission.

Signal-Digital: A digital signal (numerical display) is pulse generated and discrete. Systems used for transmission are RS-232, 4-20 ma, and 1-10 volt.

Time-of-Use Charges: Many utilities adjust energy charges for the time-of-day or time-of-year that energy is used. For time-of-day billing, onpeak energy costs will be higher than midpeak and offpeak costs. Other utilities have established winter and summer rates.

Volt (E or V): Unit of electromotive force.

Volt Amperes (VA): Unit of apparent power; EI (single phase); E x I x 1.73 (3 phase).

Watt (W): Unit of true or real power; VA x p-f.

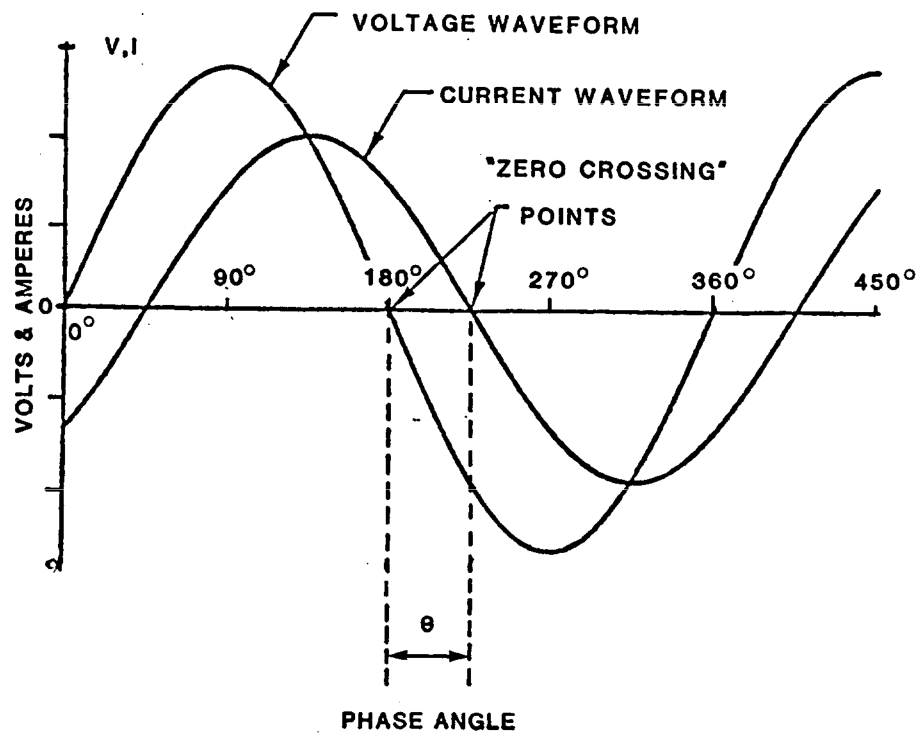
3. ELECTRIC METERS AND BILLING . In charging for electric energy, utility companies use three types of meters. These are demand, power factor, and watthour meters. Total energy charges are obtained from a watthour meter, power factor from a power factor meter, and demand values from a demand meter. Typically, watthour and demand meters are combined.

3.1 Total Energy Charges. The total energy used on an installation is recorded on watthour meters and is billed in kilowatthours. The greater the wattage of electrical devices, the higher the charges for total energy. Any method that reduces the time of operation or the power used by an electrical device will result in decreased energy charges. Many manufacturers now produce products that use significantly less energy, but perform essentially the same tasks as higher powered equipment.

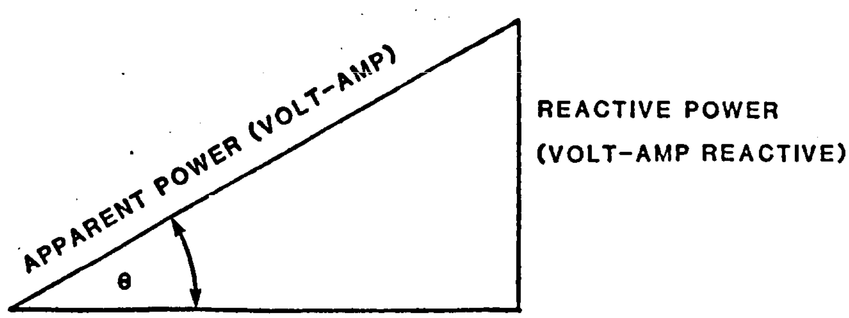
3.2 Power Factor. Power factor occurs only in AC circuits and is defined as the ratio of real power to apparent power. Power factor is also the cosine of the phase angle between the voltage and current signals. Figure 9-1 provides a graphic representation of power factor. When the current signal crosses the x-axis after the voltage signal, the power factor is said to be lagging. If it crosses the x-axis before the voltage signal, the power factor is leading. Power factor values can range from leading 0.2 to lagging 0.2, with an optimum value of 1. Typically power factor ranges from between 0.75 and 0.95, lagging.

3.2.1 Apparent Real, and Reactive, Power. Real power is actual power used by a piece of equipment and converted ultimately into work. Reactive power is not converted into work but is a measure of the stored energy (either capacitive or inductive) that must be constantly transferred between the source of power and the end equipment. Motors require reactive power to magnetize their coils. For each sinusoidal cycle of the voltage provided to the motor, the magnetic field builds up and collapses. Reactive power Is borrowed as the magnetic field is built up and, as the magnetic field collapses, the power is returned. Apparent power is power a utility must generate to operate the equipment. It contains components of both real and reactive power as shown on the bottom of Figure 9-1. If the power factor is equal to 1 (voltage and current signals coincide), then real and apparent power are equal. However, because of the power factor effect, the utility must generate a greater amount of power than required by online equipment for useful work. Since apparent power is defined as volts times amps, this requires the utility to generate more current. In addition to costing more money, the increased amperage flowing through transmission lines and into the equipment causes both to heat, which hastens deterioration and adversely affects regulation in transformers. Since reactive power does not register on watthour meters but results in added expense to the utility, the added cost is passed on to the customer in the form of a power factor charge.

3.3 Demand. Demand is defined as average power used during some utility-selected time period. Power is usually expressed in kilowatts and normal industry standards for time are 15- or 30-minute intervals, but occasionally are as long as 60 minutes. In Figure 9-2, a 15-minute time interval from 0900 to 0915 is used to illustrate demand. During this interval load varies as shown: 300 kW for the first 5 minutes, 400 kW for the next 5 minutes, and 800 kW for the last 5 minutes. The average power used during this 15-minute period is 500 kW, shown as a dotted line. This dotted line is “demand value” or simply "demand” for that 15-minute interval. Note that the area under the dotted line (demand) is exactly equal to the area under the solid line (varying load). This leads to yet another definition of demand. Demand is that value of power which, if held constant over the interval, will account for the same consumption of energy as the real power. Figure 9-3 is an actual demand graph over four time intervals. As before, demand for each time interval is shown by the dotted line with actual power consumed represented by the solid line. Again for each interval, area under the dotted line is equal to area under the solid line. If demand shown in the second interval was the highest demand for the entire billing period, it would be called peak demand and would be the value used by utility companies for



POWER FACTOR = COS θ = $\dfrac{\text{REAL POWER (WATTS)}}{\text{APPARENT POWER (VOLT-AMPERES)}}$



REAL POWER = APPARENT POWER (VA) X POWER FACTOR

= VOLTS × AMPS × COS θ

FIGURE 9-1. Alternating Current Power

billing. Since demand billing varies so greatly among utilities, it is necessary to thoroughly research and understand the policies of the utility serving the facility. Almost without exception, demand will be the major element of any electrical bill. The energy manager must try to find ways to reduce peak demand so that demand can be as level as possible. Even though utilities must be capable of providing maximum power demands, it is not necessary to provide it at all times. This will result in a significant reduction in demand charges.

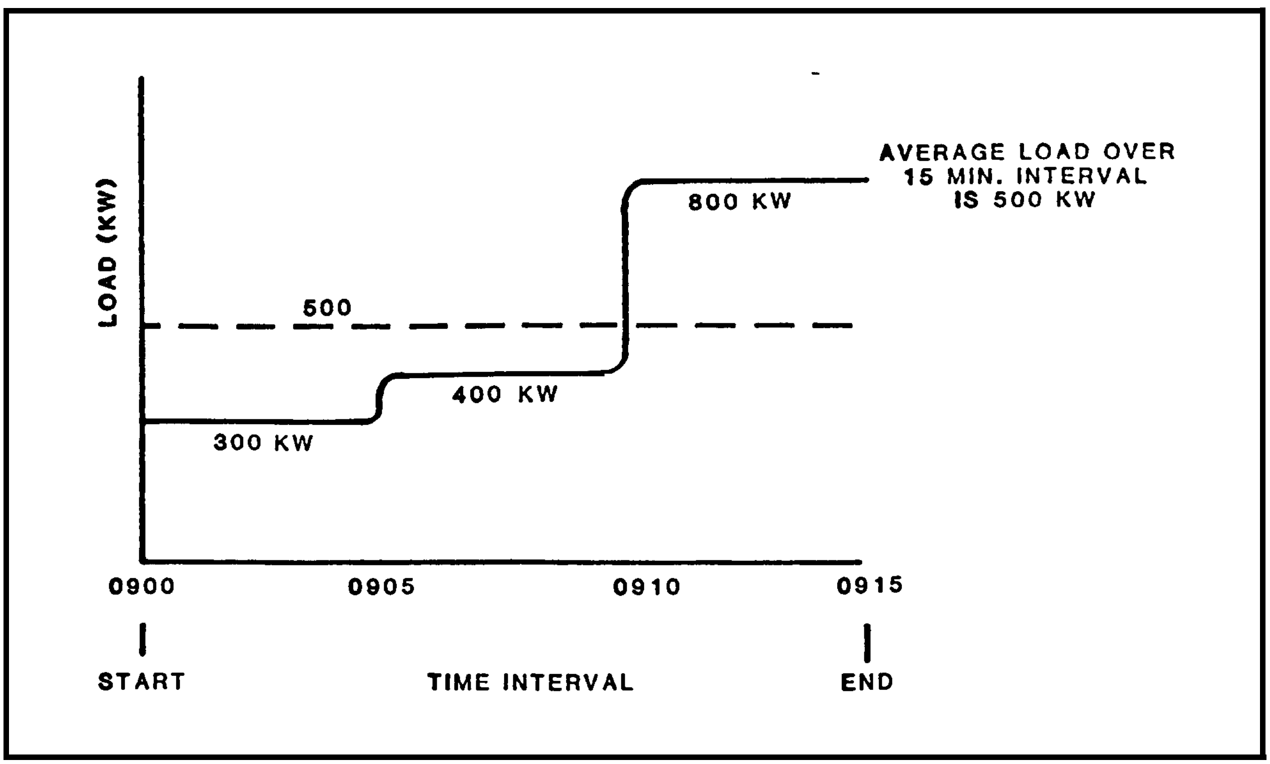


FIGURE 9-2. Demand Calculation for One Time Interval

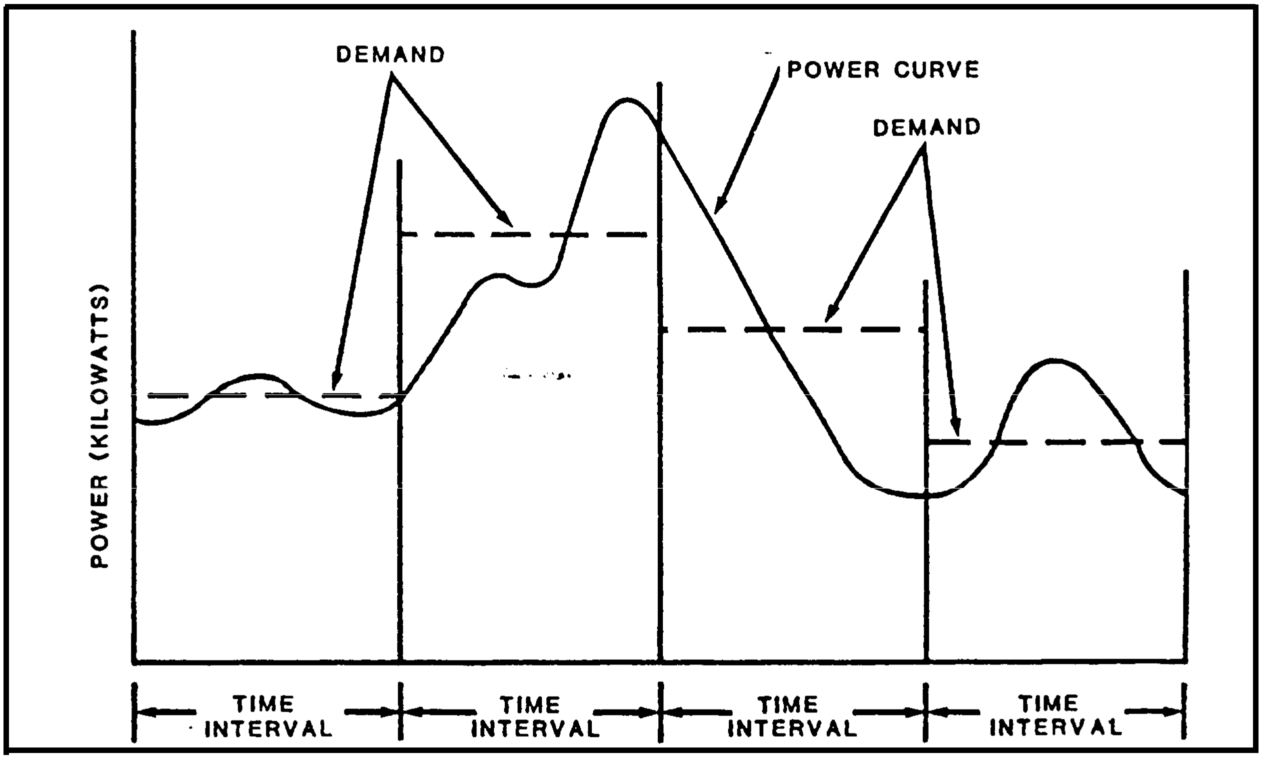


FIGURE 9-3. Demand Chart

4. **ELECTRIC METERING COMPONENTS.** A wattmeter monitors the two basic components of electrical power, current and voltage. Typical connection diagrams for a voltmeter and ammeter are shown in Figure 9-4. The voltmeter is a high-resistance device and is always connected in parallel with a source of power or load. The ammeter measures-current flowing-through a conductor is a low-resistance device always connected in series with the source of power or load. The wattmeter is a combination of both voltmeters and ammeters. It measures power flow from the source to the load. The potential coils are connected in parallel and the current coils are connected in series with the load. Typical connections for a single phase wattmeter is also shown in Figure 9-4.

4.1 Watthour Meters. The watthour meter is a carefully calibrated induction motor. It measures electrical energy by utilizing the interaction of fluxes generated by current and voltage elements acting to produce eddy currents in the rotor (disk). The eddy current flow produces lines of force which in turn interact with the flux in the air gap to produce turning torque on the disk. The speed that the disk turns depends upon the energy (watts) being measured. Each revolution of the meter disk has a value in watt-hours. A constant (K_h) represents the number of watthours per revolution. A register counts revolutions and displays the count as kilowatthours (kWh).

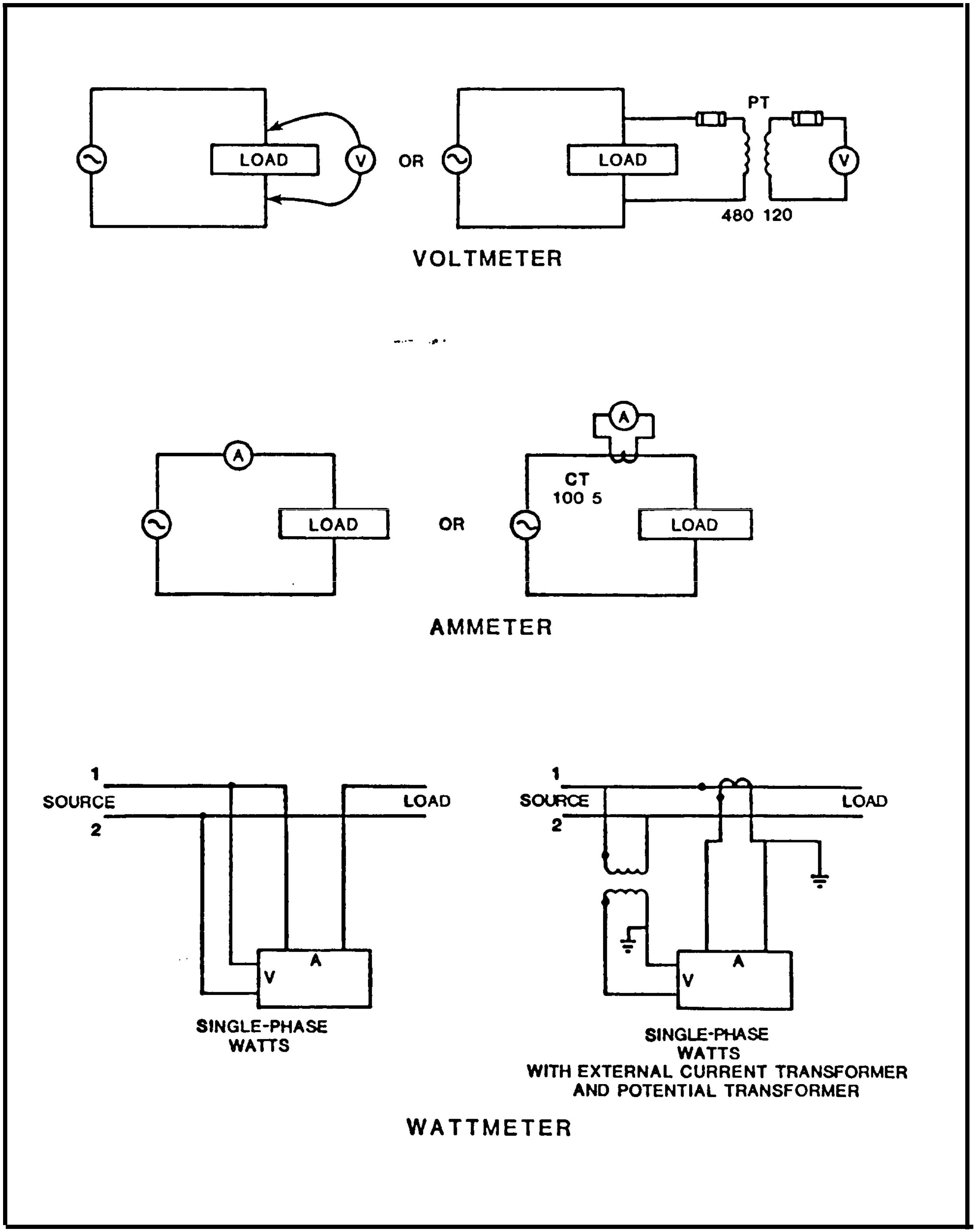


FIGURE 9-4. Meter Connection Diagrams

5. POLYPHASE A-C CIRCUITS. The energy delivered over a polyphase circuit is the total energy delivered over each equivalent single-phase circuit that make up the polyphase circuit. Energy can be measured by connecting a single-phase watthour meter in each phase and then adding up readings of individual meters. This is not commercially practicable because: it requires too many meters; it takes much more time to read the meters; and it multiplies the chance of mistakes both in reading meters and in totaling meters. The electrical industry has developed polyphase watthour meters.

6. POLYPHASE WATTHOUR METER. The polyphase watthour meter is a combination of single-phase watthour meter stators that drive a rotor at a speed proportional to the total power in the circuit. The meter consists of a multistator motor, means for balancing the torques of all stators, a magnetic retarding system, a register, and compensating devices. These components are assembled on a frame and mounted on a base.

6.1 Operating Principle. The operating principle of polyphase watthour meters, having any number of stators, is the same as single-phase watthour meters. Torque on each stator results from current in one set of electromagnetic coils and eddy currents induced in a disk, or disks, by current in the other set of coils. The torques of the several stators combine to give a resultant torque proportional to total power.

6.2 Blondel’s Theorem. Because the same rules apply to measurement of both polyphase energy and polyphase power, principal parts of single-phase watthour meters can be combined for polyphase energy measurement, much as components of single-phase wattmeters are combined for polyphase power measurement. Blondel’s theorem applies to measurement of energy exactly as it does to measurement of power. A polyphase watthour meter is built with the number of elements necessary to satisfy Blondel’s theorem.

7. METER TYPES. A wide variety of meters are available to meet almost every measuring need. Meters can be divided into two major types, indicating and recording.

7.1 Indicating Meters. Indicating meters are used to provide a measured value at a given moment, and show how instantaneous value changes as a function of time. Indicating meters may have analog pointers or digital readouts. Some meters have a built-in time delay. Many are equipped to show average use over a 15 minute to 30 minute increment.

7.2 Recording Meters. Recording meters are used to accumulate a measured value over a period of time. These meters use either dials such as a kilowatthour q eter, a paper chart (either circular or strip), or magnetic tape where readings are coded into pulses and then encoded by a computer system to record the increase in reading between reading intervals.

Section 3. METERS AND SUPPORT DEVICES

1. **INTRODUCTION.** Accurate and reliable data can be obtained using either permanent or portable meters. Permanent meters are generally installed at service entrances and at points of large power demand. To perform a power demand survey, it may be necessary to monitor many additional locations within a system. It may not be economical to install permanent meters at each location, so portable units are used. The cost of portable meters is higher than permanent meters but their accuracy is generally very good.

2. **METERING DEVICES.**

2.1 Watthour Meter. Consumption of electrical energy is measured with either a mechanical or electronic watthour meter.

2.1.1 Mechanical Watthour Meter. A mechanical watthour meter is a small, precision built, induction motor. It consists of a rotating disk, electromagnet, permanent damping magnet, bearings, geartrain, and dial assembly. The electromagnet is wound with a voltage coil and a current coil. When the meter is energized, a small current flows through the voltage coil, connected across the lines, and full load current flows through the current coil. The current in these coils sets up magnetic fields, or magnetic flux that induce small currents (called eddy currents) in the disk. These eddy currents set up their own magnetic field. The combination of fluxes, or magnetic fields, interact with one another in such a manner that the disk is forced to rotate in a positive direction. With voltage and current coils energized, the disk gathers momentum and spins faster. Therefore, a braking device to retard disk speed is provided. The braking device is a permanent magnet through which the disk rotates.

2.1.2 Electronic Watthour Meter. An electronic watthour meter consists of a current sensor, kilowatt transducers electronic totalizer, and mechanical or electronic digital display. Sensor, transducer, totalizer, and display combinations are available for readings of watthours to megawatthours. As with most electronic power monitoring equipment, the cost is high. Most electronic kWh q eters are used in conjunction with computerized energy management systems.

2.1.3 Watthour Meter Selection Criteria. Some facts that should be known or considered before purchasing and installing a meter are as follows:

- Type of service: single-phase network, 3-wire; 3-phase, 3- or 4-wire; wye (Y) or delta (Δ)

- Circuit voltage: line-to-line or line-to-neutral, depending on q eter connections. Determine if requirement exists for PT with current limiting primary fuse.

- Maximum circuit current: assume for current estimating purposes that 1 horsepower = 1 kW = 1 kVA. Determine CT ratio if load is above meter class rating.

- Mounting: socket (S) or bottom-connected (A).

- Register: 4-dial or 5-dial pointer; 4-dial or 5-dial cyclometer; cumulative demand register with 15-minute interval.

- Frequency: check value.

- Compliance to standards: ANSI C12.10, Watthour Meters.

- Special features: pulse device.

2.1.4 Watthour Meter Register. A register of a watthour meter is a geartrain designed to count the number of revolutions of the disk (Figure 9-5). Rather than displaying the number of disk revolutions directly, the register derives kilowatthours by the number of disk revolutions. Registers are either pointer type or cyclometer type (Figure 9-6).

2.1.5 Meter Terminology. To facilitate an understanding of operation, testing, and accuracy of meters, it is helpful to recognize the meaning of certain abbreviations in common use:

K_h = The number of watthours represented by each revolution of the meter disk.

K_r = The register constant. This is the value that a register reading must be multiplied by to obtain the correct kWh registration.

R_r = Refer to Figure 9-5. A ratio of the number of revolutions of first register shaft (A) to each complete revolution of the first pointer shaft (B). The gear marked A is driven by the disk shaft.

G_r = Gear reduction ratio between the disk shaft and the gear (A in Figure 9-5) which meshes with it.

TF = Transformer factor which is the product of the current transformer ratio (CTR) and the potential transformer ratio (PTR).

PK_h = Primary meter constant
= $K_h \times TF$

2.1.6 Meter Nameplate. The meter nameplate provides important information in addition to totalized watthours (Figure 9-7).

2.1.6.1 Class. Modern meters will measure accurately up to 800 percent of full load calibration test amperes. This is denoted by “CL”, or class, on the nameplate. Use Class 20 meters with instrument transformers to obtain

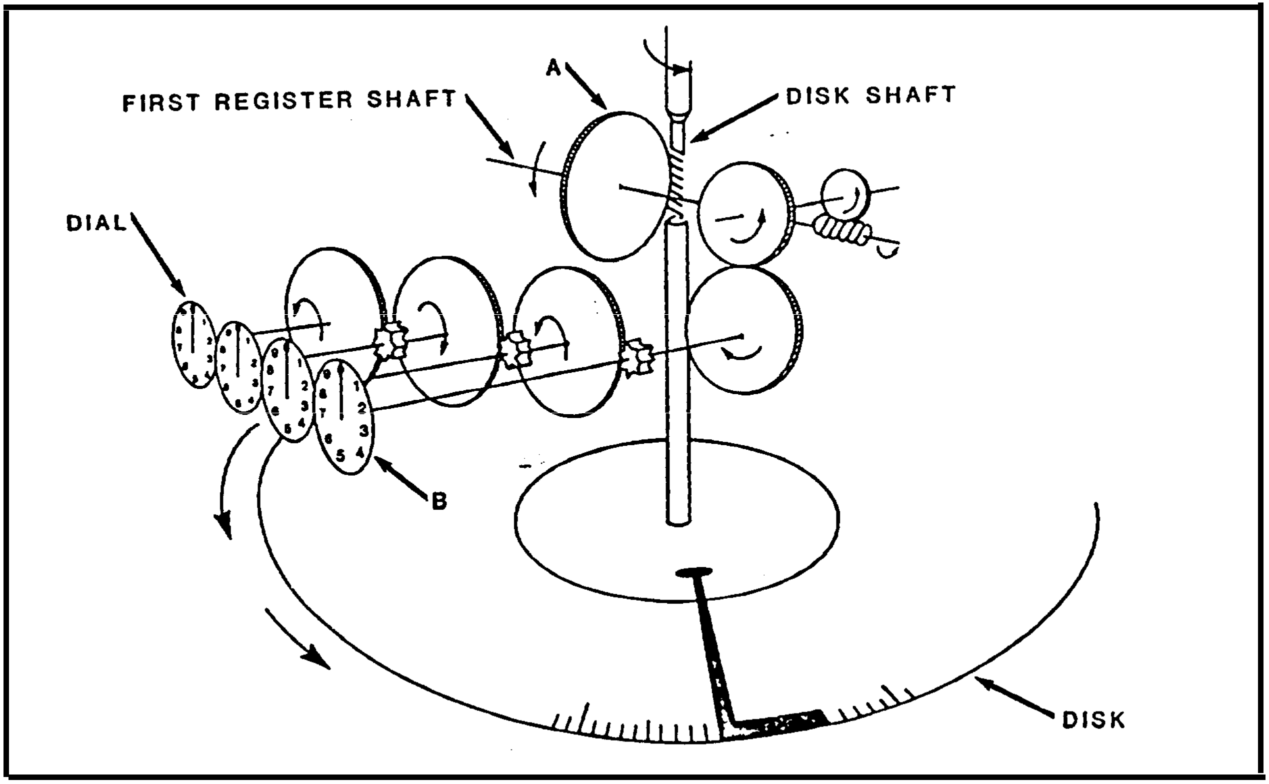


FIGURE 9-5. Watthour Meter Geartrain

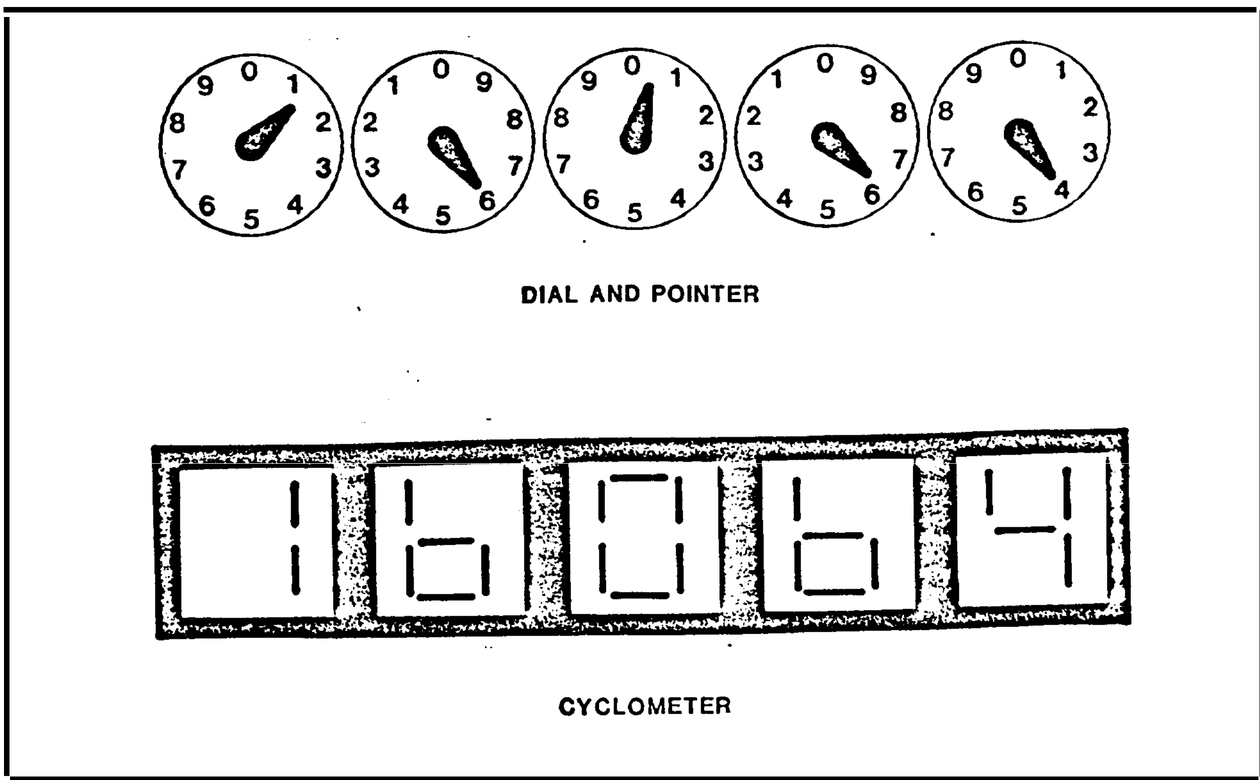


FIGURE 9-6. Meter Registers

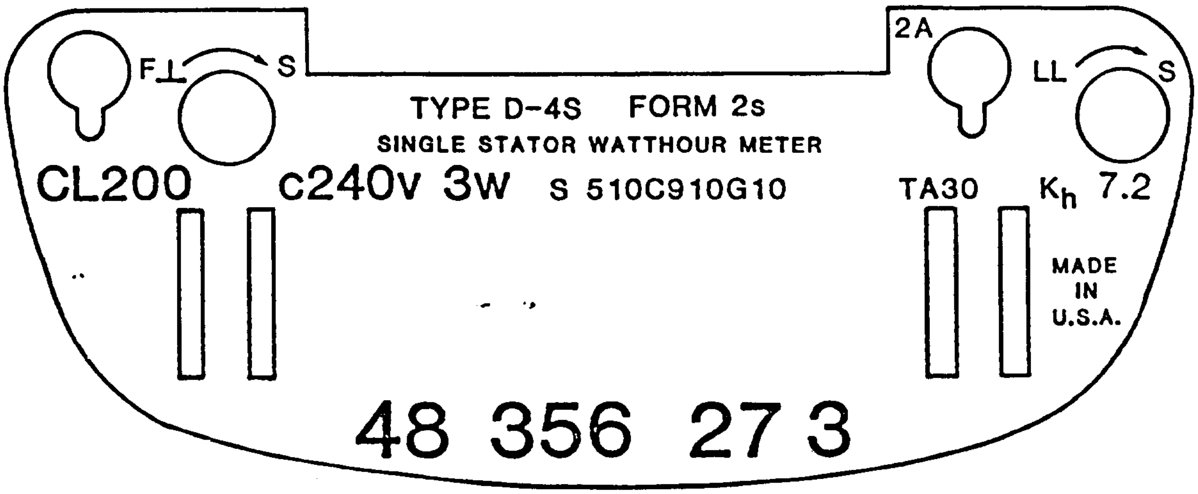


FIGURE 9-7. Meter Nameplate

straight line accuracy up to 20 amps and also use with CTs with 5 amp secondaries. Class 10 and 20 meters are for use with instrument transformers only. Class 100, 200, and 320 meters are designed to directly meter the line current.

Class 10: 2.5-amp meter with 400 percent overload capability
Class 20: 2.5-amp meter with 800 percent overload capability
Class 100: 15-amp meter with 400 percent overload capability
Class 200: 30-amp meter with 666-2/3 percent overload capability
Class 320: 50-amp meter with 640 percent overload capability

There are some exceptions to the rule. Refer to manufacturers instructions to be sure of the correct application for a particular meter.

2.1.6.2 Register Multiplier (K_r). To obtain the correct number of kilowatthours, it may be necessary to multiply the value shown on the q eter by a register multiplier or register constant K_r. The value of K_r, although shown on the meter nameplate, can be calculated as follows:

$$K_r = \frac{R_r \times K_h \times TF \times G_r}{10,000}$$

where:

- R_r = register ratio found on front plate, back plate, or frame of register
- K_h = watthour constant
- TF = transformer factor = CT ratio x PT ratio
- G_r = first gear reduction ratio usually 50 or 100 (obtain from manufacturer)

Self-contained meters, used for domestic service and small industry, usually have a multiplier of either 1, in which case no multiplier would be shown, or 10. Whenever the multiplier is more than 1, the words “multiply by”, followed by a number appear on the front plate. For transformer-rated meters, which are used with instrument transformers for heavy industrial and central station metering, the multiplier can be 10, 100, 1,000, 10,000, etc. In this case the register is supplied for only one transformer factor. The multiplier can also be numerically equal to the transformer factor. If so the register will read in terms of secondary energy and be read on a “secondary-reading register*’. In any watthour meter, the total energy in kWh is equal to the product of the watthour constant (K_h) and the disk revolutions divided by 1,000:

$$kWh = \frac{K_h \times \text{disk revolutions counted}}{1,000}$$

To determine total energy in kilowatt hours as counted by a transformer-rated meter, the secondary reading register would be multiplied by the ratio of the instrument transformers which is called the transformer factor. In a system using current transformers with a rated primary current of 20 amperes, total energy registered would equal:

$$kWh = \frac{K_h \times \text{disk revolutions}}{1,000} \times \frac{20}{5}$$

If the system also contained a PT with a 7,200 to 120 ratio, the total energy registered would equal:

$$kWh = \frac{K_h \times \text{disk revolutions}}{1,000} \times \frac{20}{5} \times \frac{7,200}{120}$$

In this example, the numbers 4 (20/5) and 60 (7,200/120) are the ratios of CT and PT respectively. Their product, 240 (4 x 60), is the transformer factor for this meter. Whatever value is shown on the secondary register must be multiplied by the transformer ratio to obtain the correct number of kWh used in the primary circuit.

2.1.6.3 Voltage Rating. Meters are available for 120-, 240, or 480-volt service as required.

2.2 Permanent Kilowatthour Meter. A typical kilowatthour meter is shown in Figure 9-8. Watthour meters are commonly known by the type of electrical system for which they are designed, such as 3-wire single phase and 4-wire delta or wye meters. Basic characteristics of a typical kilowatthour meter are as follows:

- Configuration: Kilowatthour meters are available to measure energy consumption for all types of single and polyphase circuits. Two types of mountings are available: hard-wired A-type meter and socket and plug-in, S-type meter. In addition to standard registers, three options are available: time-of-use register, demand register, and pulse initiator.

- Register: Totalized kilowatthours (kWh) are displayed either in a four or five circular dial arrangement, or in digital form.

- Range: Self-contained meters are designed for services of up to 200 amperes and 600 volts. For higher voltages and currents, potential and current transformers are required. In many situations, for safety considerations, a potential transformer (PT) is preferred when voltages exceed 277 volts.

- Accuracy: Utility companies usually specify an accuracy of±2 percent and conformance to American National Standards Institute (ANSI) c-12 series standards.

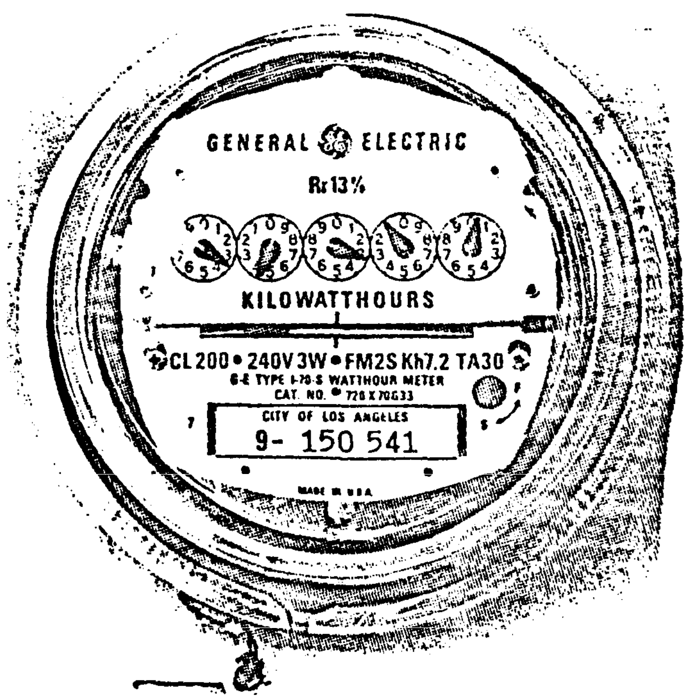


FIGURE 9-8. Kilowatthour Meter

- Installation: Power service must be interrupted to install an S- or A-type kilowatthour meter. If service cannot be interrupted, clamp-on split core transformers may be used. Core transformers are generally used as a temporary measure or for spot monitoring.

2.2.1 S- and A-Type Kilowatthour Meters. The S- or A-type designation on a kilowatthour meter refers to the counting configuration. An S-type meter is a socket-mounted meter. A socket is hard wired into position and the ❑eter is then plugged into the socket. The meter can then be removed any time without disconnecting wiring. The A-type meter is hard wired into position at the time of installation and requires complete disconnection of wiring for removal.

2.2.2 Transformer-Rated Kilowatthour Meters. If connected load exceeds 200 amperes and/or voltage of a circuit exceeds 600 volts, a transformer-rated kWh meter must be used in conjunction with instrument transformers. For safety reasons, transformers should be used when voltage exceeds 277 volts, even though meters without transformers are supplied for 480 and 600 volt service. Transformers reduce the voltage and line current to meter operating range. Both current and potential transformers are used for this purpose. Transformers can be either an integral part of the meter or a separate component. In using transformer-rated meters, it is important to know that two values of K_h may be shown on the meter nameplate. The first K_h which is a small numeric value is the K_h of the meter itself. The second K_h which may be shown as K_t, in which the subscript “t” stands for test, is the value used when the meter is being tested. There is another term which should be understood; this is the primary K_h abbreviated Pri K_h or PK_h which is followed by a numerically large number. This value is the number of watthours of primary energy for one revolution of the disk and is equal to the K_h (of meter) x Transformer Factor. The transformer factor is equal to the product of CT and PT ratios. The CT ratio is always the rating of the CT divided by 5 and the PT ratio is the voltage of the primary circuit divided by 120.

2.2.3 Three-Phase Circuits. Polyphase watthour meters are applied to both delta (Δ) and wye (Y) circuits.

2.2.3.1 Three-Phase, Four-Wire Y Circuits. A three-phase, four-wire circuit is equivalent to three single-phase, two wire circuits having a common return circuit with potentials 120 degrees apart. It can, therefore, be metered with three two-wire meters or with a three-stator polyphase meter as shown in Figure 9-9. Because the voltages of the three phases are balanced, it is common practice to use a 2-1/2 stator self-contained watthour meter to meter this circuit. Connections for a self-contained watthour meter are shown in Figure 9-10.

2.2.3.2 Three-Phase, Three-Wire Circuits. Metering of a three-phase, three-wire circuit is accomplished in accordance with Blondel’s theorem by means of a two-stator meter having current coils connected in two lines and corresponding potential coils connected from these lines to the third line. The connection of a transformer-rated meter is shown in Figure 9-11.

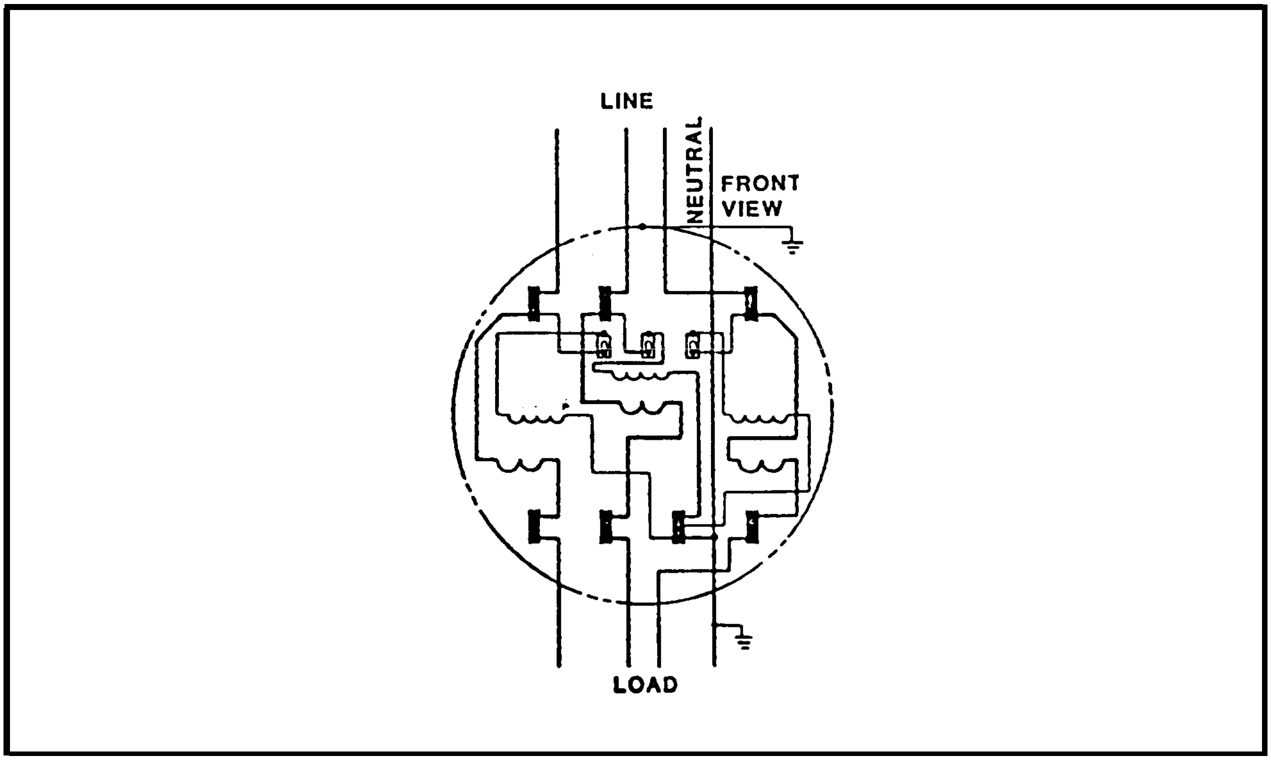


FIGURE 9-9. Three-Stator Polyphase Self-Contained Watthour Meter in a Three-Phase, Four-Wire Y Circuit

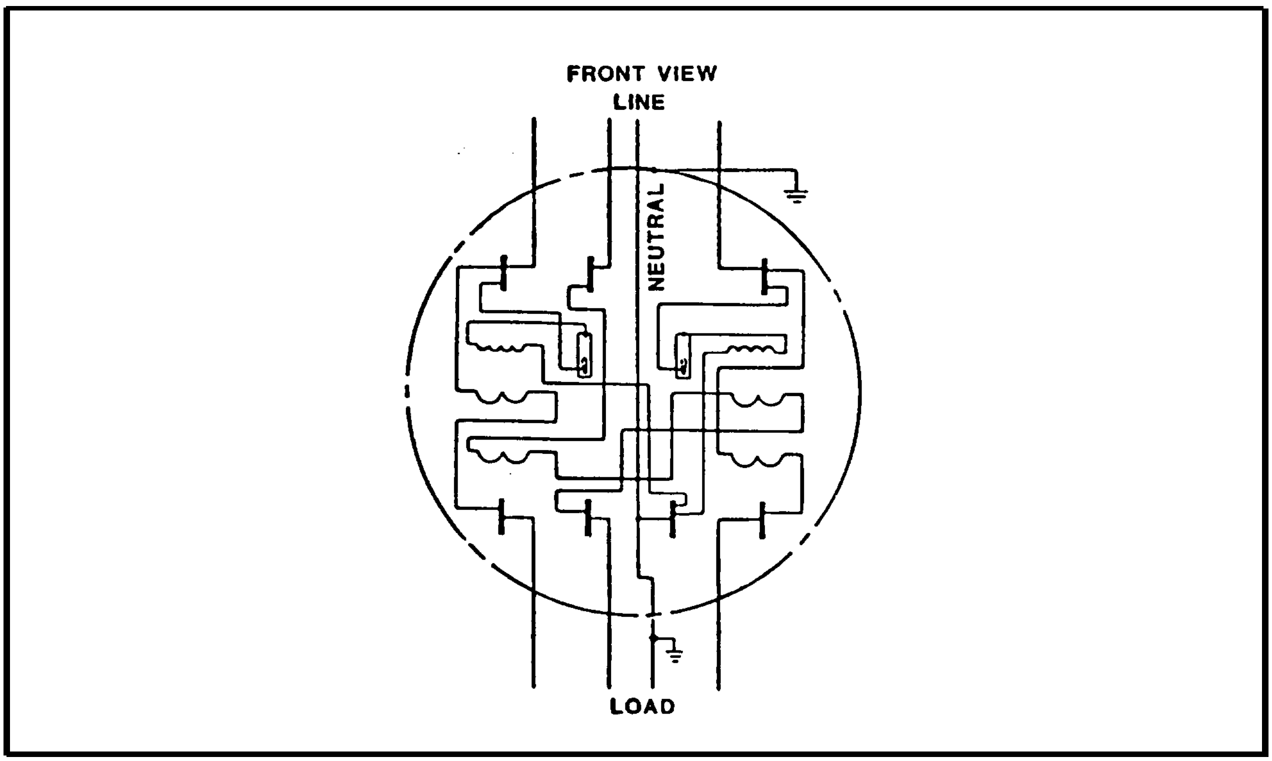


Figure 9-10. Two-and-one-half Stator Meter in a Three-Phase, Four-Wire Y Circuit

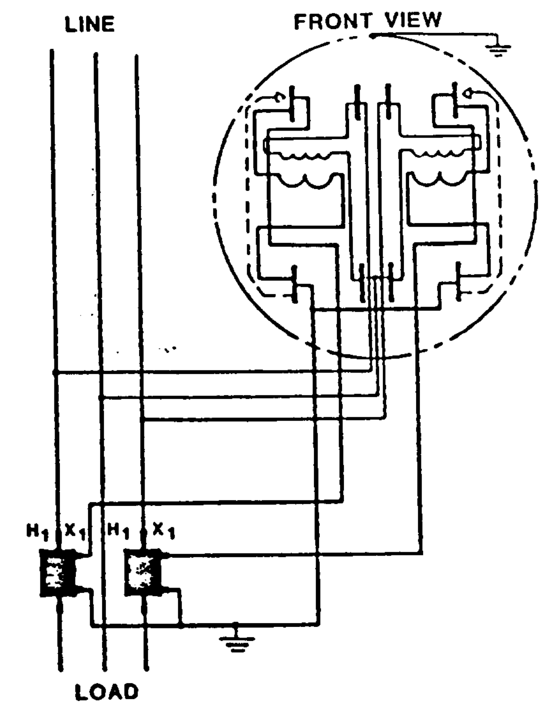


FIGURE 9-11. Two-Stator Watthour Meter Connected to a Three-Phase, Three-Wire Circuit With Current Transformers

2.2.4 Kilowatthour Meter Reading. If a meter has a dial type register, it will either have four or five dials, as shown in Figure 9-8. The correct reading for a five-dial meter is 34310; the correct reading for a four-dial meter would be 4310. Every other dial moves counterclockwise. When the pointer is between two numbers, record the lower of the two numbers. When the pointer appears to be directly on a number, look at the dial to the right. If the pointer on the dial to the right has passed "O" toward "l," then use the number the pointer appears to be on. If the pointer on the dial to the right has not passed "O," use the previous, lower number on the dial being read. Subtract the previous reading from the present reading to determine kilowatthours used during the time interval. If the words "multiply by*' followed by a number appear on the meter nameplate, the reading on the register must be multiplied by the number shown to obtain the correct value.

2.2.5 Meter Recording Developments. Recent developments in the field of meter recording promise increased accuracy and automatic processing of data. Meters currently available allow meter readings to be recorded even when the meter is inaccessible. Another development allows meter readers to record meter data on a hand-held device which resembles a pocket calculator. The hand-held device is preprogrammed to automatically evaluate the entered reading for tolerance from past readings. If beyond a programmed tolerance,

it alerts the meter reader to a possible recording error. Data must either be corrected or "force" entered, in which case this fact will be noted. The exact time the meter was read is recorded to the second. All types of meters can be serviced. At the end of the day, the device is placed into a computer interface. The interface equipment automatically feeds all the information obtained that day into computer data files. The system also prepares reports with format and information selected by the utility manager. Systems similar to this help eliminate human error.

2.2.6 Field Testing. The accuracy of a watthour meter can be checked using a simple time test. The number of watthours for any period is the product of the number of disc rotations times the meter constant (k_h). The speed of rotation of the disc indicates the use rate or watts being used. The kilowatt is a more reasonable quantity for consumption rate and the following formula can be used when timing a meter disc:

$$\text{Kilowatts (kW)} = \frac{PTR \times CTR \times k_h \times 3600 \times REV}{1000 \times s}$$

$$\text{Kilowatts (kW)} = 3.6 \times pK_h \times \frac{REV}{S}$$

where

PTR = potential transformer ratio
CTR = current transformer ratio
K_h = meter constant found on the face of the meter
REV = number of disc revolutions during observation period
s = period of observation in seconds
pK_h = primary meter constant K_h x (PTR x CTR)

A stopwatch can be used to check meter accuracy using the formula given above. The calculated kW can be compared against a known load. If load remains constant, results are quite accurate. However, since accuracy depends upon a constant load which may be impossible to obtain in the field, it may be preferable to compare the watthour meter being checked against a watthour meter standard of known performance. Since both meters will be connected in the circuit, small variations in voltage, current, or power factor will not introduce errors as both meters are observing the same loads.

2.3 Demand Meter. A demand meter is a kilowatthour meter with an accessory clock motor and counter mechanism. The basic type of demand meter indicates a single maximum demand during a given time interval, using a sweep pointer. Behind the front plate there is a pointer-pusher mechanism that advances the pointer. After each demand interval, the pointer-pusher is reset to zero by the clock while the pointer remains at its last indicated high point. Therefore, the maximum demand during a single interval is registered regardless of the number of intervals spanned. The q aximum demand, in addition to total kWh consumed, is used for billing purposes.

2.3.1 Demand Register. A demand register is the register on a demand meter that indicates maximum load demand during a given interval of time, usually a 15- to 30-minute period.

2.4 Power Survey Recorder. To assist with electrical power surveys, a power survey recorder (PSR) is recommended. The PSR is a microprocessor-based instrument that accepts all necessary parameters for analysis of any single-phase, two-phase, or three-phase electrical system. A PSR should enable recording of electrical data for various loads to provide information required for analysis. To allow demand analysis, the meter should be capable of measuring kilowatt (kW) demand and make it possible for survey personnel to correlate data acquired with time of day, day of week, or other time designation. Other parameters often required for analysis are kilovoltamperes (kVA), kilovoltamperes-reactive (kVAR), and power factor (pf). Knowledge of any two of these parameters allows calculation of the third. The choice of meter that allows selection of the parameter to be recorded will often save time during analysis. When choosing a PSR, the following additional recommended features are to be considered.

2.4.1 Portability. To enable different points in a system to be measured, the PSR must be portable rather than fixed. Physical size and weight of portable meters varies and may require consideration.

2.4.2 Full-Scale Ranges. Because of the range of load demands encountered during a survey, a PSR should be able to measure both very small and very large loads. PSRs typically have measurement limits of approximately 600 volts and 1,000 amperes. Potential transformers extend voltage range and current transformers increase current capability.

2.4.3 Split Core Transformers. Although it is preferable to install metering devices before a load has been energized, many loads may be considered too critical for shutdown. In such instances, split core transformers may enable measurements to be made. With such devices, the circuit need not be interrupted for insertion of current meter elements.

2.4.4 Accuracy. A PSR must be accurate across the entire range of scales and parameters available. Poor accuracy reduces validity of calculations that are based upon PSR data.

2.4.5 Temperature and Humidity Limits. A PSR must be capable of providing accurate, reliable information in all climatic conditions encountered.

2.4.6 PSR Voltage and Frequency Requirements. Selectable voltage inputs for a PSR is advantageous. Metering in various locations may give rise to differing voltage requirements. Should voltage requirements exceed 600 volts, PT will normally provide the needed additional capability. Although only one frequency may be encountered at any particular facility, the PSR selected should be able to measure power at whatever frequency is present.

2.4.7 Availability and Compatibility. PSRs of various capabilities are available in the commercial q arketplace. Prices and accessories vary considerably. When renting, leasing, or purchasing equipment, ensure that all components needed to undertake a complete survey are obtained. Additionally, ensure that survey equipment components are compatible with each other.

2.5 Tape Recorder Meters. A tape recorder meter is used often for periodic monitoring because it provides a graph that is easy to analyze. Tapes offer immediate data for use in comparing actual power demand with rate schedule provisions of the utility. These meters are portable and do not interrupt service when connected. The meter uses clamp-on type current transformers and may use battery power or 100 volts alternating current (VAC).

2.6 Time-of-Use Meter. Time-of-use meters have not changed for many years; improvements to them have been evolutionary rather than revolutionary. With availability of integrated circuit processors and electronic digital memories, tasks performed by these meters that were originally difficult or impossible, are now easier. This meter is based on a standard watthour meter structure with pulse output to an integral microprocessor-based register. With a precise internal clock it can be programmed to handle any time-dependent provisions in a rate schedule, such as time-of-day and time-of-year rate changes. The reduction of meter data can provide the following types of information:

- Total kWh
- Onpeak kWh
- Mid-peak kWh
- Offpeak kWh
- Onpeak kW demand
- Mid-peak kW demand
- Offpeak kW demand

2.7 Power Factor and Negative Sequence Meters. Power factor and negative sequence meters are available to meet specific needs.

2.7.1 Power-Factor-Meter. A power-factor meter indicates either a single or three-phase value leading or lagging. It requires both potential and current connections much the same as a wattmeter. Most power-factor meters are single-phase devices and are not accurate on either imbalance voltage or current on a three-phase system. Some electronic meters respond to zero crossings and, in the presence of distortion, are not accurate.

2.7.2 Negative Sequence Meter. A negative sequence meter indicates the presence and magnitude of negative sequence voltage or current, usually associated with system imbalance, fault conditions, or both.

3. OTHER ELECTRICAL METERING COMPONENTS

3.1 Pulse Device (Digital). A widely used method of demand metering is the block interval, so called because a kWh measurement is totalized over a block of time, typically a 15- or 30-minute period. The most flexible and easily computerized block interval metering technique is pulse totalization. Each pulse represents a specified amount of kilowatt hours read by the meter from

total or partial rotation of the disk. A pulse device can be retrofitted to most existing electromechanical watthour meters. These devices cause relay contacts to close at a rate proportional to load on the meter. Defined kilowatt demand is derived from relay closure pulses using the expression:

$$kW = \frac{n \times KWC}{T}$$

where:

- kW = kilowatt Demand
- n = number of pulses occurring over the counting interval
- KWC = constant number of kilowatts per pulse (demand multiplier)
- T = counting interval in hours

KWC, the watthour constant of the pulse devices, is calculated by:

$$KWC = \frac{(R/I) \times k_h \times TF}{1000}$$

where:

- R/I = number of revolutions of the rotor per pulse. This is a constant provided by the manufacturer of the pulse device.
- TF = transformer factor = CT ratio x PT ratio
- k_h = watthour constant

Two types of pulse devices are in common use, contact and pulse initiator.

3.1.1 Contact Devices. A contact device is entirely mechanical, consisting of a multilobed cam, connected into the watthour geartrain. The cam actuates one or more contact sets. All components of the device are mounted on a single backing plate that bolts into the meter mechanism under a glass dome. Three contact configurations are available (Figure 9-12). The different contact devices available service different electromechanical kW demand totalizer configurations. Slow-break contacts, for example, are used for solenoid-operated totalizers and quick-break contacts for motor-operated units. The type of break mechanism is important when contact closures from a pulse initiator are interfaced to a microcomputer through a single digital interface channel. If the sudden drop caused by the cam produces contact bounce, corrective measures must be taken to ensure accuracy of microcomputer displays. High-speed logic circuits are sensitive to contact bounce and are able to resolve a train of pulses from a single bouncing contact switch closure. This problem can be eliminated using software designed to discard any data during a specified period of time following a switch contact.

3.1.1.1 Contact Device Drives. Most contact initiators are driven by a separate worm gear on the meter shaft. Some meters have up to 360 possible gear ratios using worm gear and sector combinations. Tables for determining equivalent cam teeth (EqT) can be used, given the number of points on a cam

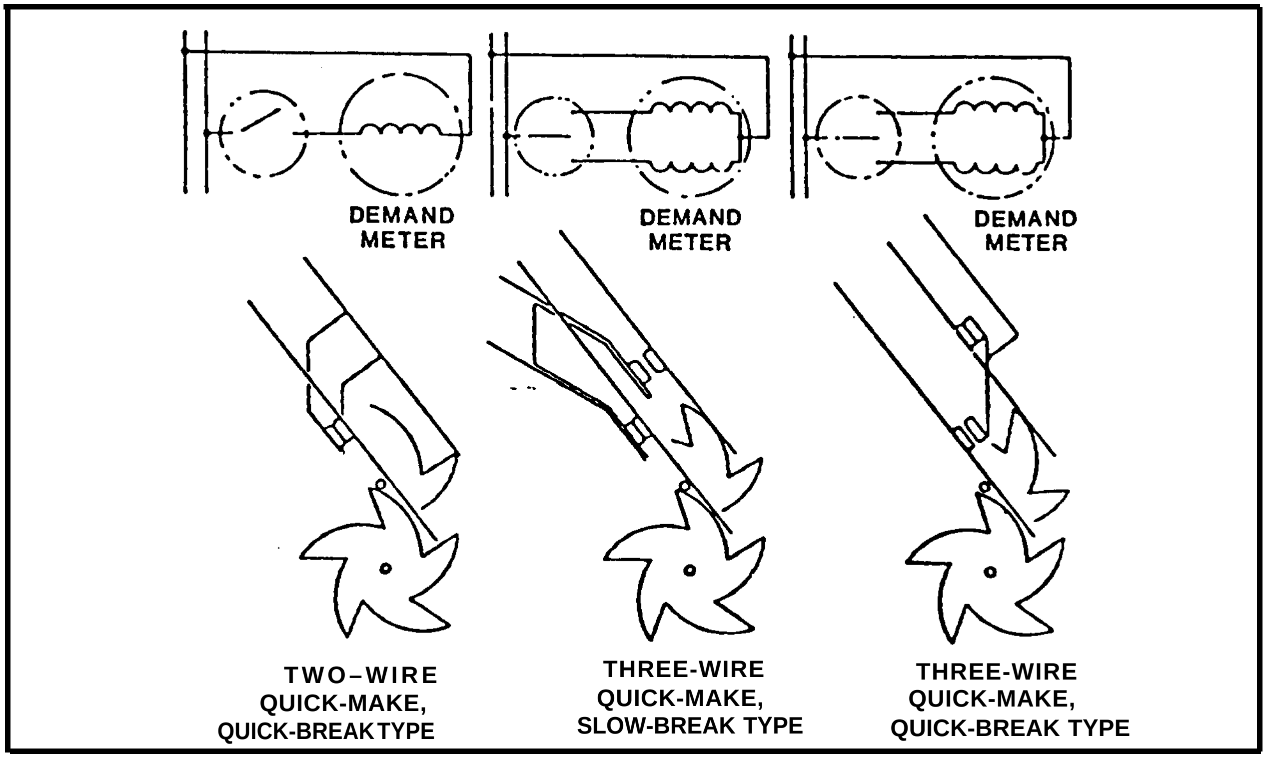


FIGURE 9-12. Contact Device Configurations

and the gear ratio from the meter rotor to the cam. These tables are available from the manufacturer. The disadvantages of contact devices have limited their installation in newer, more sensitive watthour meters. Newer meters produce lower torque per kilowatt and thus are more affected by frictional forces imposed by the cam operated switch. The increased requirement for higher pulse rates and lower spring tension on the contact have proven to increase maintenance problems. Nonmercury-wetted switch contacts experience bounce.

3.1.2 Pulse Initiators. The disadvantages of contact devices are absent in pulse initiator designs. A pulse initiator consists of a revolving shutter disk operated by a standard watthour meter geartrain. The disk, acting as a shutter, interrupts a beam of light to activate a photocell. Figure 9-13 shows the basic configuration of a shutter and the placement of the photocell and light source. The device is essentially frictionless and gives the same switch output as a contact initiator through a mercury-wetted relay. The bounceless contact closure data from pulse initiators are designed to interface with older pulse-totalizing equipment. Pulse initiator modules can be retrofitted to most watthour meters. A typical pulse initiator has one shutter disk with ten slots, producing one pulse per slot. Shutters are available with two, four, six, or eight slots.

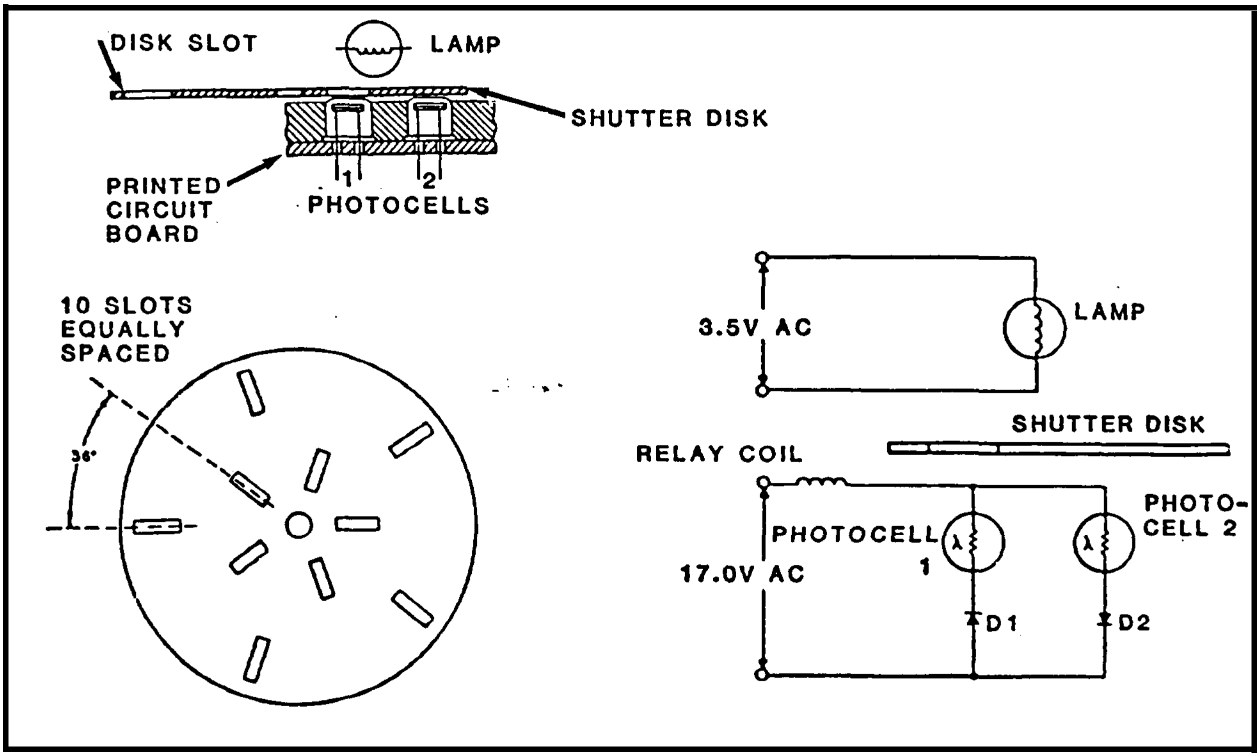


FIGURE 9-13. Photocell Initiator

3.2 Instrument Transformers. To have meters function effectively within their capabilities, current transformers and potential transformers are used. Intended for measurement and control purposes, they perform two primary functions:

- Transform line current or voltage to values suitable for standard instruments which normally operate on 5 amperes and 120 volts.

- Isolate instruments and meters from line voltage. To ❑ake this protection complete for both instruments and operators, THE SECONDARY CIRCUIT SHOULD BE GROUNDED. For grounding, see IEEE Standard 52, Application Guide for Grounding of Instrument Transformer Secondary Circuits and Cases.

WARNING

NEVER SHORT A POTENTIAL TRANSFORMER SECONDARY WINDING.

W I N G

NEVER OPEN A CURRENT TRANSFORMER SECONDARY WINDING.

3.2.1 Current Transformer. Current transformers (CT) are designed to have the primary winding connected in series with a circuit carrying current to be measured or controlled. The secondary winding will then deliver a current proportional to the line current for operation of meters, instruments, and relays. In cases of portable instrumentation, ammeter and current coils of the wattmeter usually obtain their current signal from a clamp-around current transformer. This CT is used to step down line current to a level that can be conveniently metered, generally to 5 A or less. The CT surrounds the primary conductor and produces a secondary current proportional to the magnetic field created by the primary current in the conductor being measured. The ratio of primary current to secondary current is known as the CT ratio or CTR. CTs are normally rated in values to 5 A such as 100:5, 1000:5, and 5000:5. These values indicate how many amperes flowing in the primary conductor will cause 5 A to flow in the secondary winding. Current transformers must be selected for each application as shown in Table 9-1. In each instance, the secondary winding ratio should result in a secondary output of 5 amps at full-rated primary current. As an example, a 1,000-amp current transformer has a ratio of 200 to 1 and a 50-amp transformer has a ratio of 10 to 1. The secondary of a *CT* shall always be a complete circuit whenever there is current flowing through the primary conductor. Thus, leads of a CT shall never be fused and shall always be either connected to a low-resistance ammeter movement or shorted together by means of a jumper wire, screw, or switch on a CT shorting terminal strip.

Figure 9-14 is an example of how an ammeter, voltmeter, wattmeter, and a watthour meter may be connected through instrument transformers to a high-voltage line. It is extremely important that manufacturer's manuals be followed to ensure a proper meter hookup.

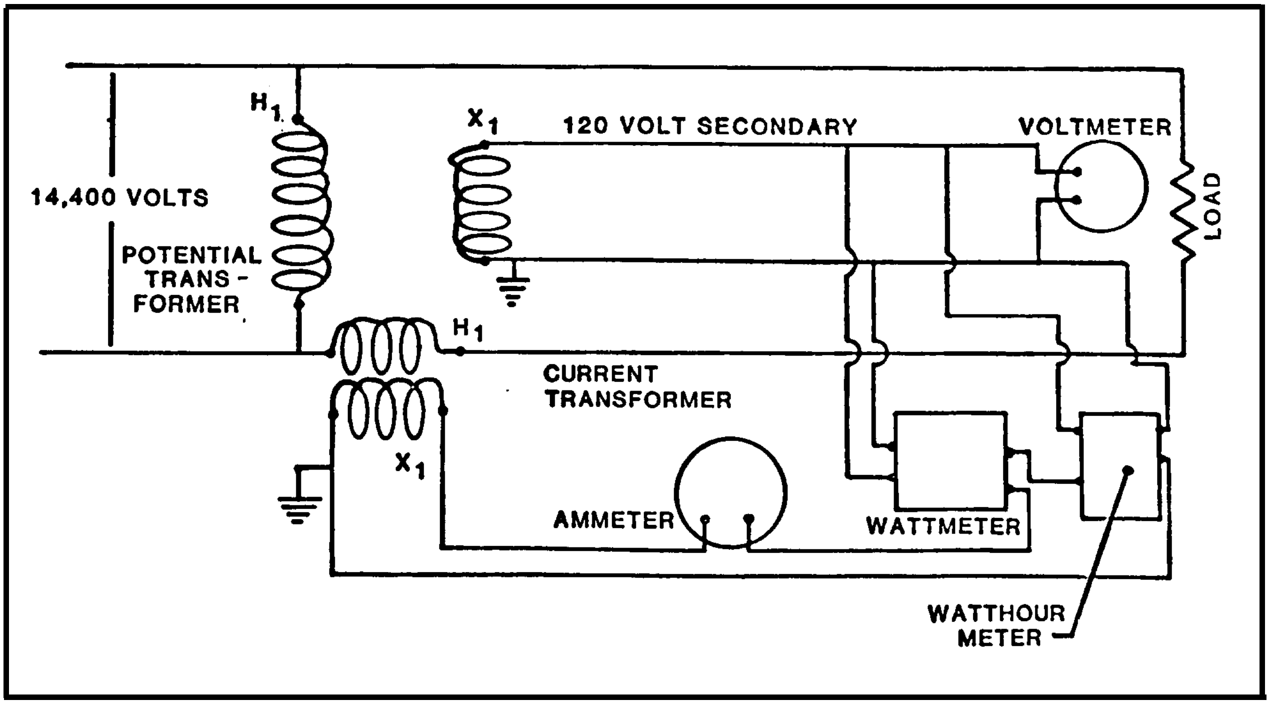


FIGURE 9-14. Connection of Instrument Transformers

3.2.1.1 Mechanical Construction. Current transformers are classified as follows:

- **Window type:** This type has a secondary winding completely insulated and permanently assembled on the core, but has no primary winding. This type of construction is commonly used on 600 volt class current transformers.

- **Bar type:** Same as the window type except a primary bar is inserted into the window opening. This bar can be permanently fixed into its position or be removable.

- **Wound (wound-primary) type:** "This type has primary and secondary windings completely insulated and permanently assembled on the core. The primary is usually a multiturn winding.

3.2.1.2 Electrical Connection. The following are types of CTs based on electrical connection:

- **Single primary:** This term is frequently applied to current transformers having a single primary electrical circuit and is generally used to distinguish them from current transformers having series-parallel primary windings.

- **Window type with one or more primary turns:** A single conductor straight through a window type transformer is a "one turn primary" connection.

  If this single conductor is taken through the "window" twice, the nameplate primary rating is reduced by 1/2. (Multiply meter reading by 1/2 the CT nameplate ratio).

  If on a single-phase, three wire circuit, two different leads are taken through the same window transformers, the nameplate primary rating is reduced by 1/2 (multiply meter reading by 1/2 the CT nameplate ratio).

- **Double ratio:** Double ratio units are built either with a two-part series parallel winding or with a tap on a secondary winding.

3.2.2 Potential Transformer. Potential transformers (PT) are designed to have the primary winding connected in parallel with a circuit, the voltage of which is to be measured or controlled. The secondary winding will then deliver a voltage proportional to line voltage for operation of meters, instruments, and relays. A PT is used to reduce line voltage to a level to match the meter rating, generally 120 V. The ratio of primary to secondary voltage is known as the PT ratio or PTR. The leads on a PT shall always be fused and shall never be shorted together. Voltage transformers are available in many accuracy classes; it is important to select one suitable for a specific application. Figure 9-14 shows how a voltmeter would be connected to a potential transformer in a high-voltage circuit. In this instance the turns ratio would be 120 to 1. As with CT hookups, the manufacturer's manual should be consulted and followed to ensure the meter is properly connected in the circuit.

TABLE 9-1. FULL-LOAD LINE AMPERES FOR THREE-PHASE* TRANSFORMERS OR LOADS

kVA	SECONDARY VOLTAGE						
	208	240	480	600	2,400	4,160	13,200
1.5	4	4	2	1			
3	8	7	4	3	1		
5	14	12	6	5	1	1	
7.5	21	18	9	7	2	1	
10	28	24	12	10	2	1	
15	42	36	18	14	4	2	1
25	69	60	30	24	6	3	1
37.5	104	90	45	36	9	5	2
50	139	120	60	48	12	7	2
75	208	180	90	72	18	10	3
100	278	241	120	96	24	14	4
150	416	361	180	144	36	21	7
200	555	481	241	192	48	28	9
300	833	722	361	289	72	42	13
400	1,110	962	481	385	96	56	17
500	1,388	1,203	601	481	120	69	22
750	2,082	1,804	902	722	180	104	33
1,000	2,776	2,406	1,203	962	241	139	44

For single-phase transformers or loads, multiply the above three-phase values by 1.73.

Example 1: A 5 kVA single-phase transformer has a secondary line current of 12 x 1.73 = 20.8 amperes at 240 V when operating at full load.

Example 2: Assume the load to be metered is fed by a 500 kVa transformer at 208 volts on the secondary. If the load is metered on the secondary side of the transformer, the ammeter will see a max current of 1,388 amps. Thus a current transformer with a ratio of 400 to 1 (2,000/5) should be used.

3.2.2.1 Secondary Circuit. Potential transformers are classified by the type of design of the secondary circuit.

- Single secondary: In general, standard rating potential transformers, 15 KV class and below, are supplied with a single electrical secondary circuit designed for 120 volts.

- Tapped secondary: There are applications where it is desirable to have two or more values of secondary potential available from the same secondary winding. This is particularly true where it is desirable to connect the secondary winding in delta or wye, for three-phase circuits, and obtain the same secondary voltage.

  For such applications, the' transformer secondary is rated at 120 volts with a tap at 69.3 volts.

- Double secondary: Unlike current transformers, double or multisecondary potential,transformers have individual secondary electrical circuits on the common magnetic core. These windings may or may not be tapped. Each secondary is affected by the burden conditions on the other secondaries.

3.2.3 Transformer Accuracy. Because of the function they perform, all instrument transformers must be classified as to accuracy. The two most important specifications for these transformers are ratio accuracy and phase-angle error. Phase-angle errors should be less than 50 minutes for use with analyzers of the 99 percent accuracy class and 10 min. or less when used with instruments having accuracies of 99.75 percent or better. It is noted that control transformers are not suitable for metering since their voltage can be off by 10 percent.

3.2.4 Instrument Transformer Polarity. When instrument transformers are used with instruments or relays which operate only according to the magnitude of the current or voltage, the phase position or direction of flow of current is of no consequence; connection to the secondary terminals may be reversed without changing indication of the instrument. When instrument transformers are used with watthour meters, in which the operation depends on the interaction of both current and voltage, the direction of current in the primary and secondary windings must be known. This is indicated by marking one primary and one secondary terminal with a distinctive POLARITY MARKER. When current is flowing toward the transformer in the marked primary lead, it is flowing away from the transformer in the marked secondary lead.

3.2.5 Grounding. It is always desirable to ground a transformer rated meter and also to ground secondaries of both the current transformer and the potential transformer. This avoids danger of high electrostatic voltages that might otherwise be present as a result of the capacitance (condenser effect) of the potential-transformer windings. This grounding practice also minimizes hazard from high voltages reaching the secondary circuit as a result of insulation breakdown due to lightning surges or other abnormal circuit conditions.

Section 4. METER INSTALLATION

1. **METER INSTALLATION AND USE.** To avoid injury during meter installation, the following warnings must be observed.

WARNING

Eye protection must be worn while switching or when otherwise opening circuits where *an* arc or flash is possible.

WARNING

Wear rubber gloves while working on energized circuits, on any series conductors, or in a Danger Zone, to avoid electrical shock.

WARNING

Wear rubber gloves while handling any items in contact with, *or* likely to contact, energized wires and when using live-line tools, to avoid electrical shock.

WARNING

Discharge any possible capacitance charge in disconnected cables to avoid accidental arc or discharge that might cause injury.

WARNING

Use proper type and size of fuse puller to avoid unexpected actions and risk of possible injury.

WARNING

Do not work on energized circuits unless absolutely necessary. If work must be done, another qualified person must be present with instructions to reenergize circuit if anything unforeseen occurs.

WARNING

Only qualified electricians will install electric meters.

1.1 General Information. Before starting any work, the person in charge should assemble the entire crew for a job briefing. The job briefing should include an outline of the following items:

- The work to be done.
- Each crew member's part in the job.

- The hazards known or anticipated during the task.
- Safety precautions to enforce while working.

If during the course of the work, changes in the plan become necessary, members of the crew who are affected must be called together and the changes explained.

1.1.1 Prior to Installation. Before installation of any equipment, the person in charge should identify all the circuits present. Conductors should be identified in terms of circuit and voltage, both at the point where work is to be done and at all switching and grounding points involved. Prior to installation of metering equipment, the supervisor of the building, or area of the building receiving its electrical supply from the metering point, should be advised of the installation. Barricades or barriers should be installed to prevent unauthorized entry into the area near the meter installation.

1.1.2 Portable Meters. To collect reliable data while performing an electrical energy survey, the proper meter for the job must be obtained. The following list of equipment parameters should be considered:

- Maximum voltage rating.
- Maximum load current (in amperes).
- Accuracy.
- Number of simultaneous demand values to be recorded.
- Power factor ranges.
- Full-scale ranges.
- Temperature working limits.
- Input power requirements.
- Type of meter enclosure.
- Weight.
- Overload protection.

1.1.2.1 Connecting the Meter. The items listed below are supplemental to manufacturers' instructions and are provided to assist in safer and more accurate meter operation.

- Make only one connection at a time. Work on only one conductor or point at a time.

- Check all selectable meter settings to confirm configurations for monitoring desired parameters.

- Check zero for all parameters.

- Observe polarity of all meter connections.

- Connect additional ground; use #12 copper wire.

- Reset all counters, integrators, and totalizers.

- Some meters require warmup time. Allow meter to acclimate to conditions at the test site.

- Replace all protective covers when setup is complete.

The following items, coupled with the recommended safety equipment (as shown in the safety summary), assist in successful completion of electrical power surveys using a PSR. The required quantities of items listed depend on the number of personnel performing electrical power surveys. Ample quantities of the following items should be kept in good condition and readily available.

- Barriers and warning signs.

- Live-line and switch tags.

- Padlocks and locks.

- One-line diagram of building.

- Insulated flashlight.

- Clamp-on voltammeter and ohmmeter.

- Approved three conductor extension cord with grounding plug.

- Electrical insulating tape.

- Light meter.

1.1.3 Permanent Meters. The more common types of permanent meters include the S-type mounted with a socket and the A-type which is hard wired in its permanent position. These meter types are designed for original installation in new buildings or as retrofit equipment when conditions warrant monitoring an in-place electrical service. In most cases, electrical service must be interrupted to install or remove a meter.

1.1.3.1 Socket-Connected S-Type Meters. To install the S-type meter, perform the following procedures:

(a) Meter should be installed plumb and in a location that is free of heavy vibration.

(b) Make sure that meter socket is mounted securely in place and in a position that the rotor shaft will be vertical when meter is mounted.

(c) TO ground meter frame and surge protectors (if present), good contact between ground straps and socket rim must be ensured. To ensure good ground, scrape off any paint between straps and socket rim at points of contact before fastening them together.

(d) Make connections to socket terminals per manufacturer's instructions. For connections of pulse initiators, consult manufacturer's instructions for the particular type of device being operated.

(e) Plug meter into socket. Make sure meter terminal blades engage with socket jaws. To ensure connection of meter to its load circuit before line voltage is applied, always insert meter load (bottom) terminal blades into socket jaws first; when removing, withdraw them last.

(f) Push meter into place so that the base fits tightly against socket rim. If sealing rim is used, place it around adjoining meter cover and socket rim. Position rim so that clamp is at bottom.

(g) Seal or latch rim as required.

(h) For connections of pulse initiators, refer to manufacturer's instructions for particular type of end device being operated by the pulse initiator.

1.1.3.2 Bottom-Connected A-Type Meters. These meters have mounting and terminal chamber dimensions that conform to industry standards. Therefore, mounts for bottom-connected A-type meters are interchangeable with all brands of A-type meters. To install an A-type meter, proceed as follows:

(a) Locate mounting holes in mounting base of meter.

(b) Obtain necessary type and size q ounting screws suggested by meter manufacturer.

(c) Mount meter base in desired position.

(d) Meter base should be grounded. Use number 12 AWG copper wire for grounding purposes. Complete grounding process before external connections are made to meter.

(e) Make external connections to meter as shown in manufacturer's instructions. The connections should be made by working from right to left. This ensures complete connection of meter to its LOAD circuit before LINE voltage is applied. Disconnection of meter should be made in reverse order.

(f) For connections of pulse initiators, refer to manufacturer's instructions for particular type of end device being operated by the pulse initiator.

2. COMMON ELECTRICITY METERING PROBLEMS. Problems often encountered in the field while metering electricity fall into four categories: wrong meter, meter incorrectly wired, multipliers not calculated correctly, or the meter is not calibrated.

2.1 Wrong Meter. This problem occurs when the meter is incorrectly specified for the circuit. A common example of this is when a two stator meter is specified for a four wire wye circuit. The meter is often wired as if the circuit is a delta circuit. However, if the phases are even minimally unbalanced, the current flowing through the neutral wire will not be metered and the readings inaccurate. SOLUTION: Consult the manufacturers literature and specify the proper meter for the circuit.

2.2 Incorrect Wiring. It is estimated that between 5 to 10% of the electricity meters on navy bases are incorrectly wired. There are several ways the wiring can be wrong.

2.2.1 Current leads, potential leads, or instrument transformers could be reversed or out of rotation or phase. The phase angle between the current and the voltage for each phase to be wrong, resulting in erroneous readings by the meter. SOLUTION: Ensure meter IS wired correctly. Determine the nature of the load being metered and estimate its power factor. Then use a power factor meter on the incoming potential and current wires to determine if the meter is reading the estimated power factor.

2.2.2 Blown Potential Fuses. If fuses protecting potential transformers (PTs) are blown, the meter could be missing one or more phases of the load and running at 1/3 or 2/3 of normal speed. SOLUTION: Ensure that fuses for PTs are not blown. On most panel mounted meters, each PT circuit has a small light that, when lit, indicates that the circuit is operating properly.

2.3 Incorrect Multipliers. The multipliers have been incorrectly calculated, resulting in the register readings being multiplied by the wrong numbers. This often occurs when meters have been switched to a new location with different sized CTs or PTs, or when a meter has been repaired and the register changed. SOLUTION: Ensure that the values for the CT and PT ratios, K_h, R_r, and G_r are correct. Recalculate K_r, the register multiplier, to ensure it is correct.

2.4 Uncalibrated Meter. **Meters built by major manufacturers are designed to run several years before calibration. However, depending on their use, navy meters should be calibrated from once per year to once every 5 years.**
SOLUTION: Field calibration of permanent meters can be performed by installing a portable meter In series with the permanent meter, timing the revolutions of the rotor, and comparing the kW demand of the permanent meter to that of the portable meter. This method should be accurate to within 5-lo% . More accurate calibration requires the removal of the meter from the circuit to use a calibration stand.

Section 5. ELECTRICAL ENERGY SURVEYS

1. DATA FROM DEMAND SURVEYS. Electric bills may provide only the peak demand for a month or the average of three or four highest peaks for a month, depending on how the particular utility company computes maximum billing demand. No indication is given of how this peak compares to the balance of the demand profile for the interval, nor what combinations of loads caused the peak. This information can only be acquired by monitoring key points in the internal electrical system.

1.1 System Information. Each electrical system is different, but system information for each follows a similar pyramid pattern, with overall system information available at the peak and an increase in detailed information available as the base is approached. Figures 9-15, 9-16, and 9-17 illustrate the process of demand surveying in three phases.

1.2 Survey Starting Point. The survey should begin at the utility service entrance. If a pulse initiator is in place, a demand analyzer can be connected without need for voltage or current connections. If a pulse initiator is not installed, additional connections will be required. Consult the user manual for the demand analyzer before making any connections.

1.2.1 Utility Service Entrance. A utility service entrance demand profile gives considerable information about the overall system. Comparing profiles obtained from system monitoring will provide answers to the following questions and will prove valuable in analyzing an electrical system.

(a) What is the peak facility load in kilowatts?

(b) What day of the week did it occur?

(c) Was the peak the same each day? If not, why?

(d) What is the after-hours load? Was it the same each day/night?

(e) Is there evidence of power wasted by starting equipment before hours or letting it run unnecessarily during lunch or after hours?

(f) HOW does the peak compare with the utility company's demand charge for the previous month?

(g) Could a slight change in startup time save money?

(h) HOW long did it take the facility to reach full power load after starting time?

(i) Is there a tendency to anticipate quitting time?

(j) What is the maximum power factor of the load? What is the minimum?

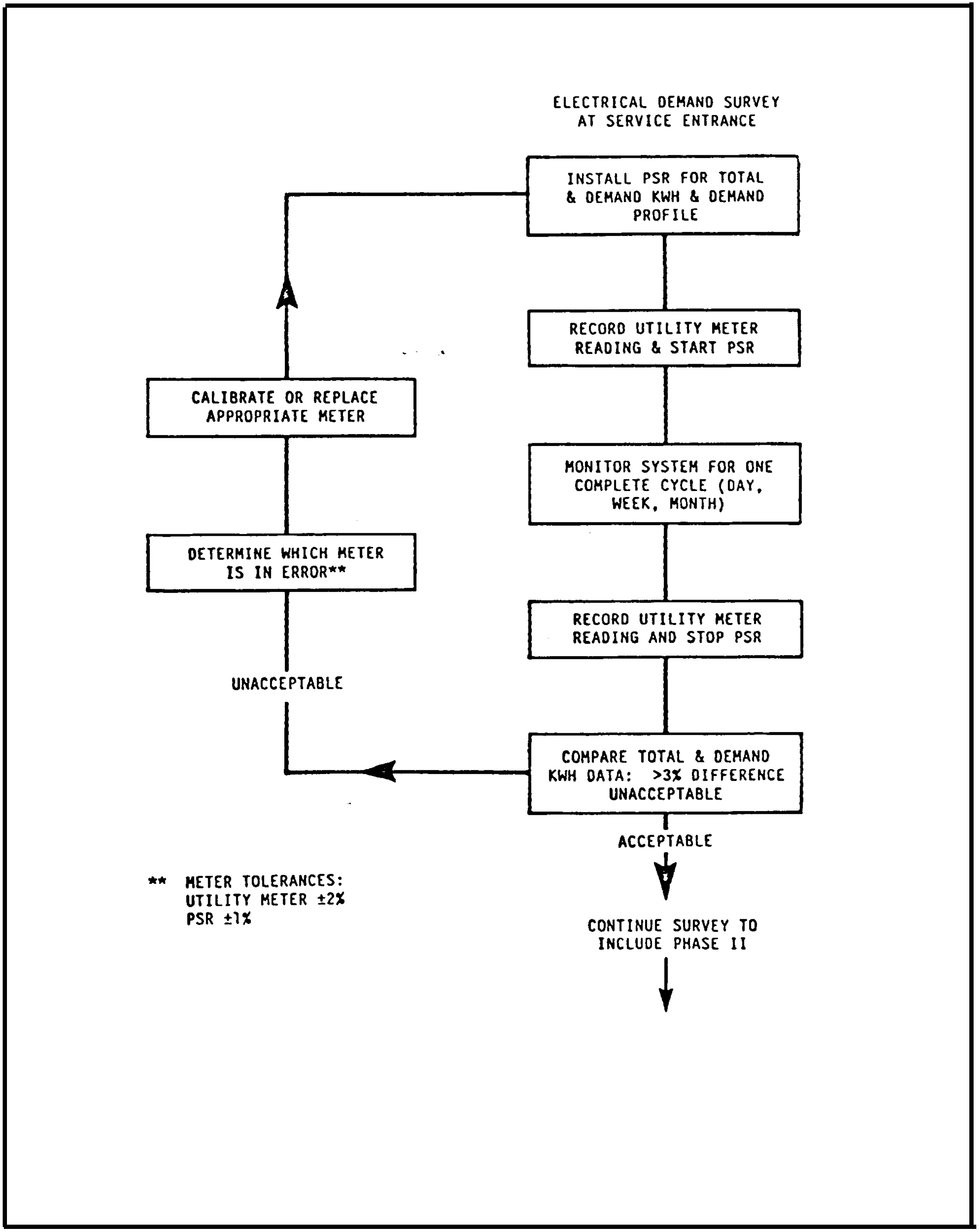


FIGURE 9-15. Demand Survey, Phase I

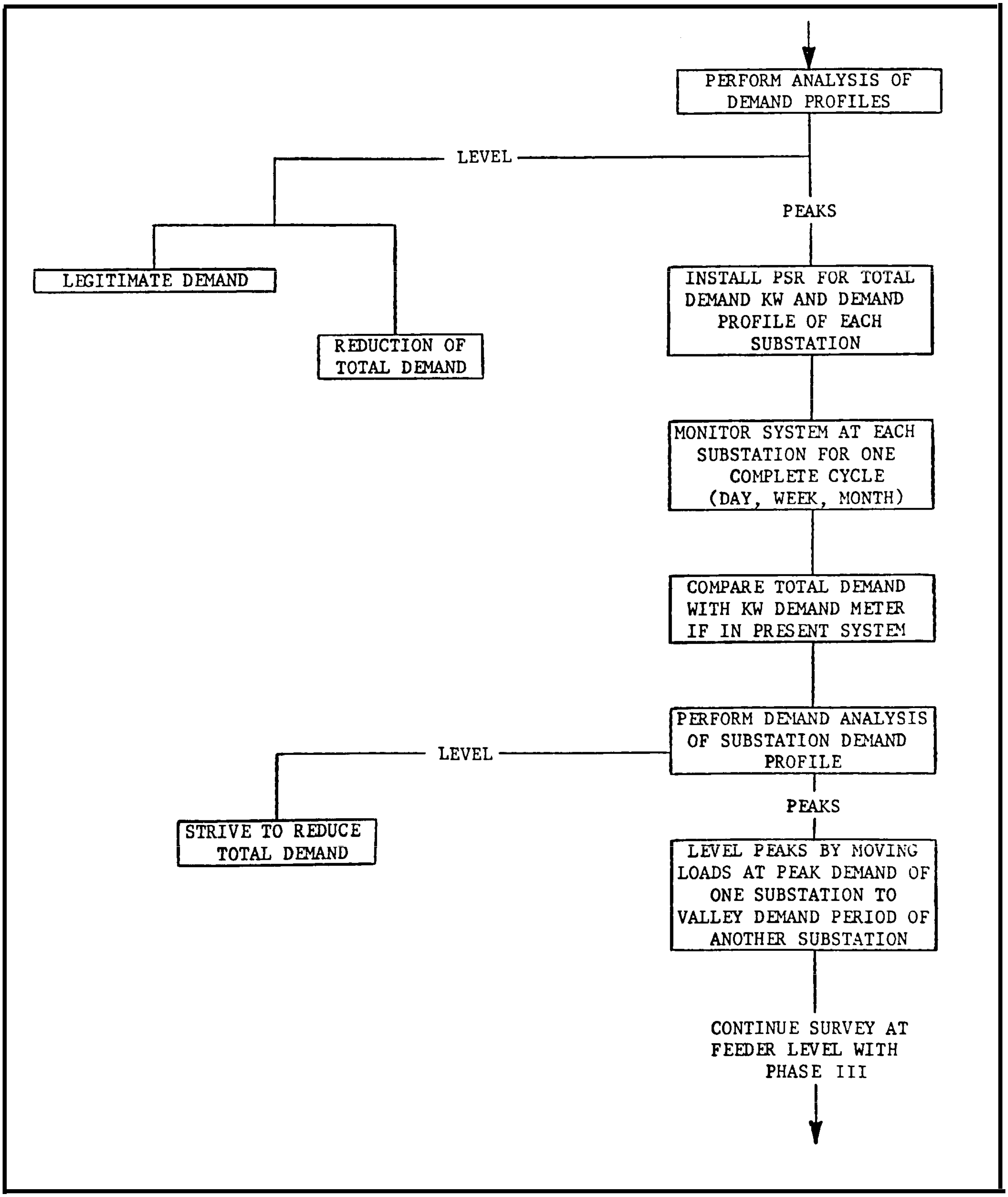


FIGURE 9-16. Demand Survey, Phase II

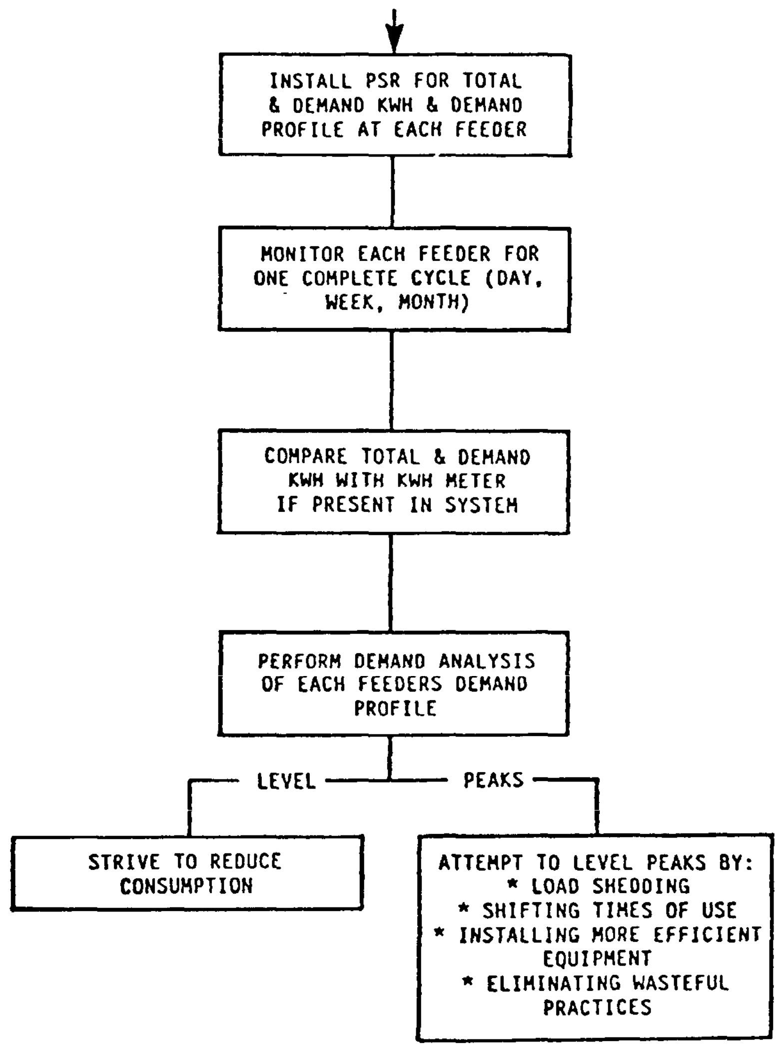


FIGURE 9-17. Demand Survey, Phase 111

(k) When did the minimum power factor occur? What caused it?

(1) How does the power factor compare with the one on which the previous power bill was based?

(m) What is the voltage drop between the main power bus and the various major consumers.

If the profile peaks radically at only a few points, then demand leveling could lead to a reduction in demand charges. An exception to this may exist because of peaks caused by individual pieces of equipment, or allied pieces, that must operate together. It may be preferable for the equipment use to be shifted to a reduced-demand charge period. If the demand profile is reasonably level, it may indicate that reduction of demand charges can only be obtained through planned reduction in total consumption.

1.3 Specific Load Profiles. The next step in a demand survey is to record electrical power consumption by substation, building, and department. This enables the facility engineer to associate some of the causes of the undesirable conditions with more specific load profiles. Some information obtained from recording instruments at the building level will provide answers to the following questions.

(a) Did the building equipment start on time in the morning and after lunch?

(b) What is the load at noon and night?

(c) How long did it take for the building and each department to reach full power load after startup?

(d) To what extent was quitting time anticipated at noon and in the evening? Were machines left running idle?

(e) What is the idle load in the building?

(f) Does the building have a peak load that corresponds to the total facility peak? What causes it? Could a change in scheduling reduce the power demand?

(g) Is there evidence of pyramiding loads which cause excessive or pulsating peaks?

(h) Does anything in the record offer explanations as to the waste of power?

(i) What proportion of the demand charge and energy consumption should be allocated to this building?

(j) What is the power factor?

1.4 Equipment Load Profiles. After obtaining the total building electrical power load records, the next step is to test individual pieces of equipment. These tests determine what each individual piece of equipment is contributing to the total electrical power load, and whether it is operating within specifications.

1.4.1 Equipment Monitoring. If electrical power consumption is excessive, the equipment may be overloaded or faulty. If equipment is drawing more current than expected, it may indicate the need for a more efficient motor. Answers to such questions are especially informative in interpreting performance of automatically-operated equipment. The record shows when and how long each machine was operated and how long it was idle. It discloses waste if automatic equipment is not functioning properly. Monitoring individual equipment will answer the following questions;

(a) What are maximum, minimum, and average loads for the equipment? Are they within specifications?

(b) If the motor is not the correct size, what is the horsepower of the motor that should replace it?

(c) Is there sufficient voltage at the motor terminals?

(d) How much does the unit contribute to peak load?

(e) Could the equipment schedule be rearranged to reduce peak load?

(f) Is load on a unit a contributor to any loss of productive effort shown by the department record?

(g) What is the idle load of this unit?

(h) Does the idle load show any marked increase since the last survey?

(i) Does the record show any characteristic which indicates a faulty condition in the motor or the associated equipment?

(j) How does the record compare with other records of similar equipment?

(k) Does the record show any data valuable in reducing energy consumption?

2. INTERNAL SURVEYS. Assuming that improvements seem possible, then further investigation must be carried out to determine what load makeups are causing the demand peaks and what can be done to shift load combinations to reduce these peaks.

2.1 Demand Survey Example. Each electrical system is different, but they all spread out like a pyramid, with total facility information available at the peak and more detailed information available as the base is approached. At whatever point a demand analysis is made, it must be carried out for a full

cycle of operations so that normal permutations and combinations of loads are encountered. Depending on the facility, a full cycle may be a day, but more likely a week, and sometimes a complete month or billing period is required. Figure 9-18 shows a typical situation with three substations and three feeders per substation. The survey should begin at the utility service entrance.

2.1.1 Service Entrance. A utility service entrance demand profile gives considerable information about the overall plant. If it peaks radically at a few places then demand leveling could lead to a reduction in demand charges, unless the peaks are being caused by individual or allied pieces of equipment which must operate together. It may be profitable to shift these loads to a reduced demand charge offpeak period, if the rate schedule includes such time-dependent provisions. If the demand profile is reasonably level, it may indicate no need for load shifting.

2.1.2 Substation and Feeders. In Figure 9-18, the demand of the three substations and the individual feeders supplied by the substations are monitored. Provided that the demand studies are carried out at comparable times in the plant operating cycle, and that successive operating cycles show reasonable consistency, the three substation demand profiles should be roughly equal to the overall plant profile. The sum of the individual feeder profiles should roughly equal the respective substation demand profile. Figure 9-19 shows this concept for substation No. 2 and feeders 2A, 2B, and 2C. These plots were obtained on four successive Wednesdays from data obtained by monitoring the three feeders and the substation output from 8:00 AM to 8:00 PM.

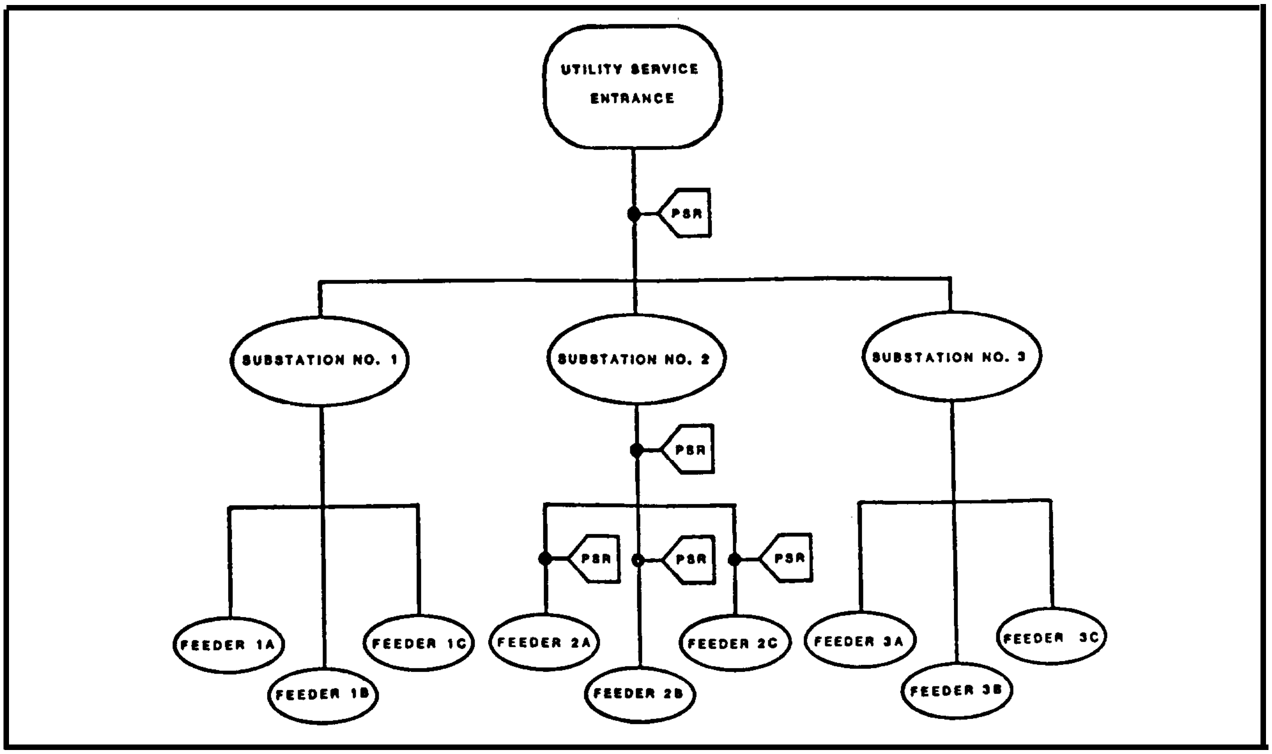


FIGURE 9-18. Three Substations With Three Feeders Per Substation

2.1.3 Profile Analysis. In Figure 9-19 the peak demands occur around 10:00 AM and during the period from 1:00 PM to 5:00 PM. After the morning buildup, feeders 2A and 2C show level demand, with the substation peaks being principally caused by erratic loading of feeder 2B. If the demand on feeder 2B is made up of many small loads, then a better time distribution of these loads would level demand on this feeder and consequently on substation No. 2. Other possibilities are to shift loads on feeders 2A and 2C away from the peaks of feeder 2B, or to transfer some of the peak loads on any of the feeders to second shift. If these steps are not possible, then the peaks from this substation could be mated to the valleys from other substations.

2.1.4 System Management. Developing a series of plots for an entire facility and designating the principle loads on the plots, gives a clear picture of the overall demand situation, building from the base of the pyramid to the peak. Such information is invaluable in developing procedural steps that reduce demand charges or developing an energy management system program.

2.2 Periodic Studies. It is important to remember that changing market forces and equipment requirements create needs to modify a system load makeup. Therefore, periodic studies should be carried out, at least at the utility service entrance, to make sure that gains from a previous energy audit are not outdated.

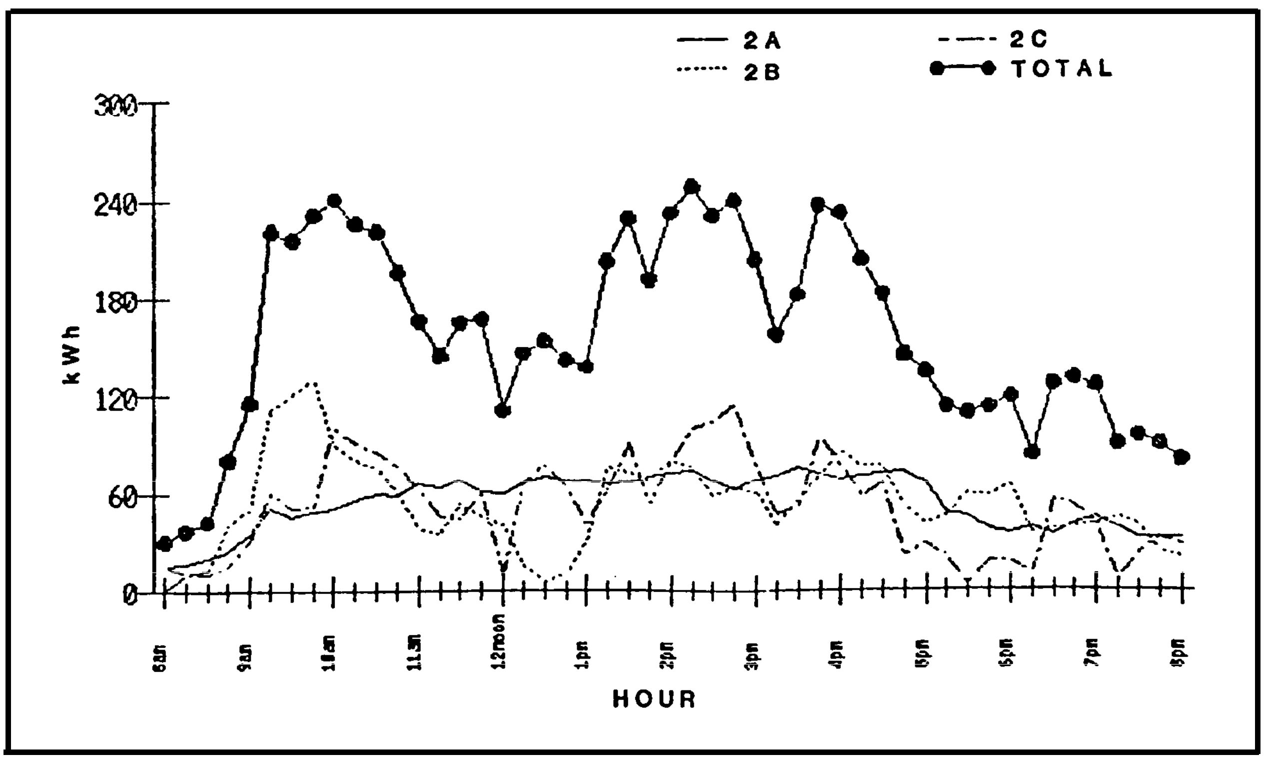


FIGURE 9-19. Demand Profiles

CHAPTER 10. INSTRUMENTATION IN METERING

1. DESCRIPTION. Today's versatile electronic instrumentation allows managers to manage their systems 24 hours a day without using meter readers. The old method of collecting data using meter readers, who periodically inspect and log readings for strategic meters, creates a reaction delay to situations that should be corrected immediately. For instance, in the event of a line break, modern instrumentation would report the leakage upon occurrence as opposed to later discovery by a meter reader. An instrument alerts the operator that an excessive flow is passing through the system and the manager can then take immediate action. The meter can record the time and magnitude of the leakage, actuate alarm systems, and provide a variety of signals to initiate corrective action. In addition to providing-information on occurring events, electronic instrumentation provides records for later viewing to analyze trends or significant changes or billing information.

1.1 Operating Principles. An electronic instrument records the amount of a media passing through a meter and converts it into an electrical signal to be displayed in meaningful units. Other equipment can be controlled based on this signal. Consumption registered on an electromechanical or electronic totalizer shows the amount of the media that has passed through the meter over a period of time. Quantity may be displayed in a variety of units, not necessarily those displayed on the meter register. A second common instrument display is the instantaneous rate through the meter.

1.1.1 Meter Output. The output is typically shown on an analog (a needle and scale instantaneous reading meter) or digital (a digital readout meter reporting in discrete scale increments) indicator. Output may also be fed to a variety of chart recorders for permanent records.

1.1.2 Meter Signals. Along with the basic outputs, modern processors are able to provide a variety of signals for use with computers and other process management equipment. Some examples of output signals are: 4-20 mA, 2-10 VDC, O-5 VDC, and 3-30 VDC pulse. If the data is to be entered into a computer system, an interfacing module can prepare the data signal for an RS-232C input application. These signals offer an infinite variety of system control functions and can provide data readouts to both local and remote locations. The receiving equipment is able to convert the data received from a simple slave device into a base for a complete management system.

1.2 Local Instrumentation. Figure 10-1 shows a meter sending an electronic signal to a local instrument that displays the instantaneous use rate on an analog indicator and the total use measured on a totalizer. The analog use rate indicator may be replaced with a digital indicator or a variety of recording devices, if desired.

1.2.1 Meter With Onsite Recorder. Figure 10-2 shows an equivalent package with a 31-day strip chart recorder that replaces the analog indicator of the system in Figure 10-1. This configuration is used when data is required at

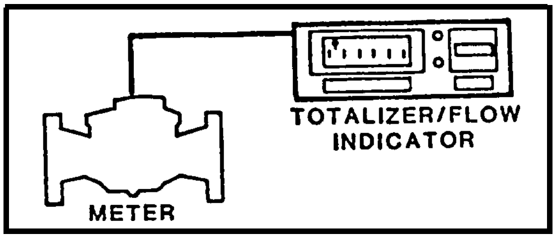


FIGURE 10-1. Meter With Onsite Monitoring

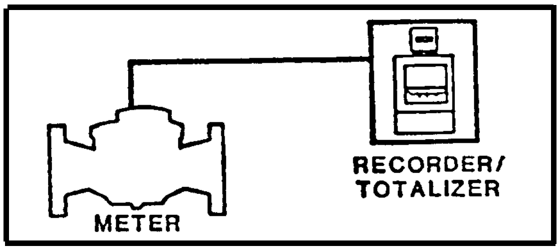


FIGURE 10-2. Meter With Onsite Recorder/Totalizer

close intervals and no other data or functions are required of the metering operation. This arrangement would be useful to the onsite operator who requires an Immediate data record.

1.3 Remote Instrumentation. With the advent of inexpensive PCS, software, and new meter technologies, most utilities management functions can be automated within the foreseeable future. Meter data may be transmitted to remote locations by adding a transmitting option and the appropriate transmission equipment to the metering system. The transmission distance is limited by the equipment and the availability of a communications link between the meter site and the remote location. Figure 10-3 shows an expansion of figure 10-1 with the meter-generated data being displayed onsite and also being transmitted via the telephone system to a remote point that may be many miles from the meter site. If information is not required onsite, the onsite instrument can be replaced with a transmitting module as shown in Figure 10-4. Transmitted data can be analyzed automatically using specially adapted PC software, and reports such as the Utilities Cost Analysis Report (UCAR) and the Defense Energy Information System (DEIS) II Report can be generated and transmitted automatically. Because of the cumbersome nature of present systems of meter reading, recordkeeping, billing, and reporting, very little analysis is performed. Modernizing the way utilities are managed will save money, improve readiness, and provide better support to the fleet.

Remote monitoring technology will enable a utilities mangement system that will automatically record metered consumption data for major utilities at an activity and send data to a central PC. The PC will receive the data, and automatically generate utility bills for tenants. In addition, remote monitoring equipment installed at major steam, electric, compressed air, and chilled water generating plants will provide detailed information on equipment status and performance. This data, along with utility company cost and consumption data, operations and maintenance personnel cost data, material cost data, and other information, will be used to automatically generate various analyses of utilities costs and performance. These analyses will allow managers to make decisions that will result in optimized operations in the present and future.

1.3.1 Remote Interfacing Kilowatt Meters. There are two reasons for providing a kilowatthour meter with a pulse initiator. The pulse initiator allows for monitoring of the load center on a temporary basis or collecting remote data on a permanent basis. In either case, pulse initiators are manufactured with a variety of output signal parameters and care must be taken to ensure compatibility of components. For applications requiring a distance between the pulse device and data collection point of over 50 feet, the signal may require reinforcement. Increased voltage and the use of signal repeaters are two common methods used. Do not attempt any signal manipulation without first referring to the manufacturer's instructions of all equipment involved.

1.3.2 Transmission to TWO Points. The need to have data transmitted to two remote points is frequently necessary in the wholesaling or custody transfer of the commodity. In these applications, both the supplier and the end user must have meter data readily available to them. Figure 10-5 depicts a means of accomplishing the task with one telemetry transmitter. Figure 10-6 shows a system with two data channels if the channels must be isolated.

1.3.3 Repeater Transmission. Repeater data transmission systems provide the user with a relatively inexpensive means of sending data to a remote point, as shown in Figure 10-7. Although repeaters accomplish the transfer of data from local to remote points at a cost of approximately 10 percent of what other transmission systems cost, they do have limitations. The primary consideration when a repeater is contemplated is its requirement for a dedicated wire pair. When using a repeater, no other signals may be on the wire pair. Repeaters also have finite distance limitations, usually expressed in ohms rather than distance, because the gauge of transmission lines varies. Typically, a repeater system is limited to a maximum transmission loop resistance of 4,000 ohms. Another means of data transmission is the use of a modem through existing telephone lines which is cost effective since the cost is only the price of a telephone call.

1.4 Computer Management. The system shown in Figure 10-8 usually requires telemetry of data from a number of meters in a system, to a central point where the data is converted into a computer compatible signal (RS-232C). In this system, the computer continuously monitors the data lines. It immediately warns the operator when a signal is not within programmed limits.

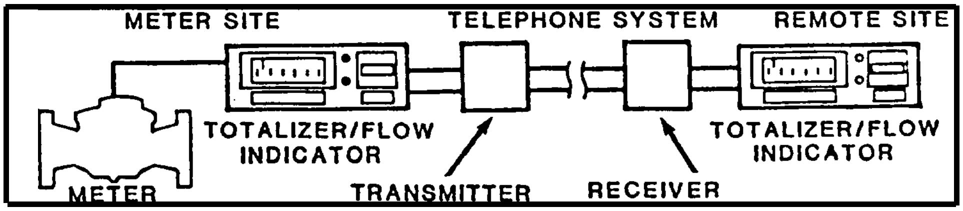


FIGURE 10-3. Onsite and Remote Monitoring

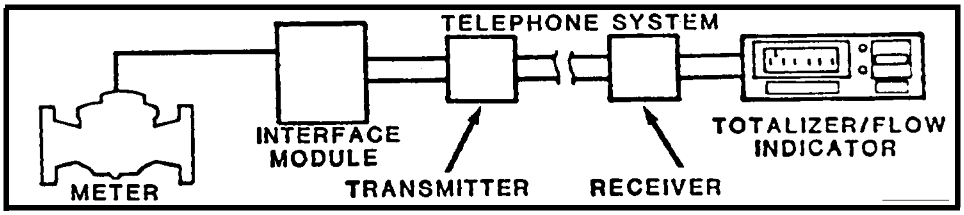


FIGURE 10-4. Metering System With Interface Module

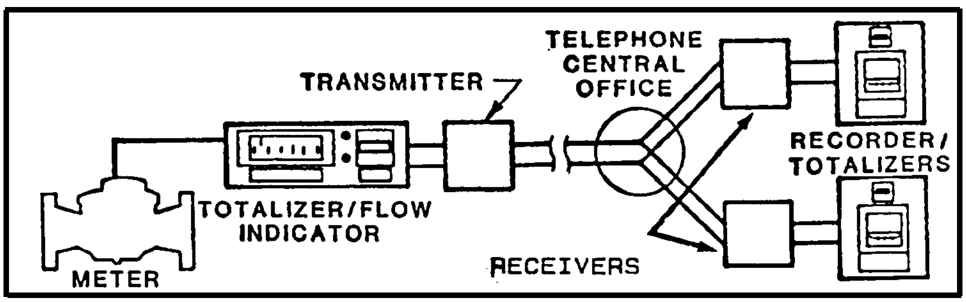


FIGURE 10-5. Single Transmission Split in Communication Link

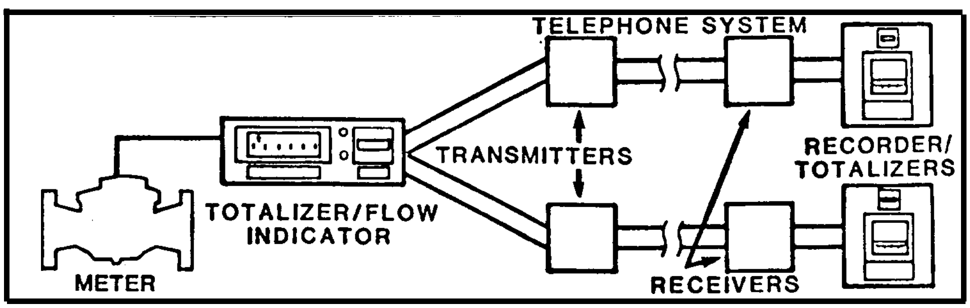


FIGURE 10-6. TWO Transmission Modules--Two Data Channels

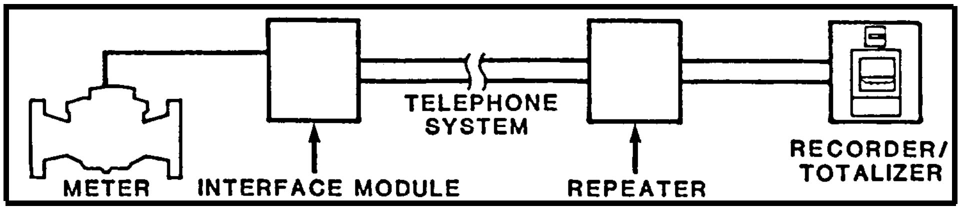


FIGURE 10-7. Extended System Using a Repeater

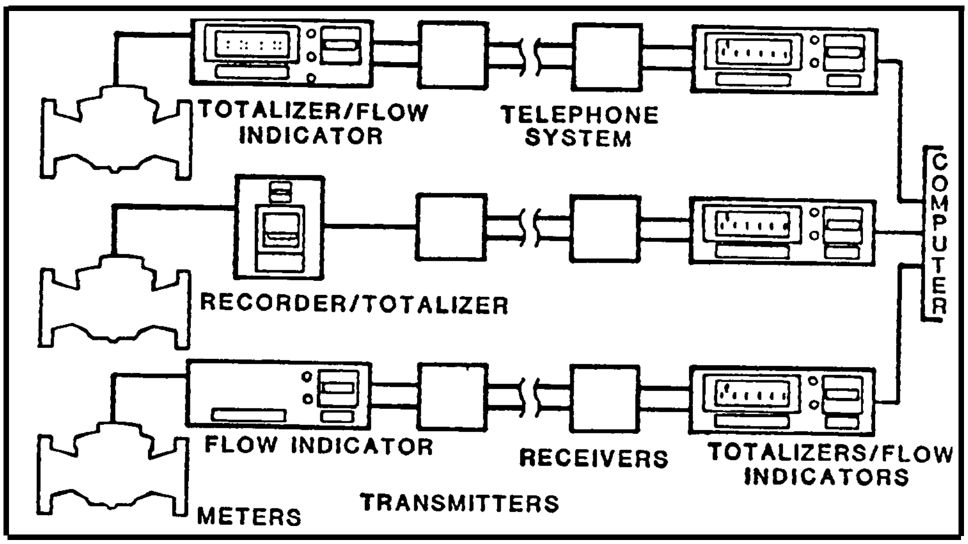


FIGURE 10-8. Multi-Input System

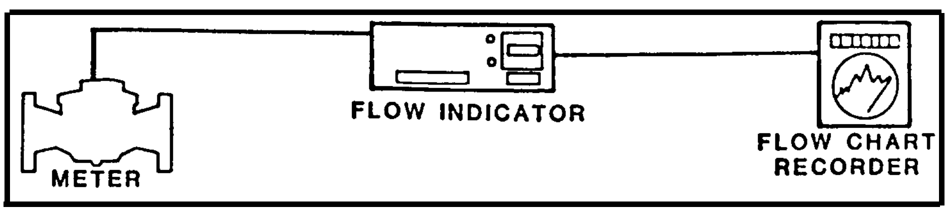


FIGURE 10-9. Chart Recording System

On demand, the computer prints a complete analysis of the system and output totals to present. When strategically located meters are connected to a computerized system with critical parameters, the computer can instantaneously provide the information necessary to monitor, control or operate a system.

1.5 Demand Billing. As the cost of energy, materials, and labor increases, there is a need to limit the large, intermittent demands on systems and to encourage utilization during offpeak periods. To accomplish this task and identify systems not in conformity with policy, instrumentation is required.

1.5.1 Control Parameters. Control parameters depend on the characteristics of the system. Some systems are limited in peak capacity and q ust control maximum use. There may be other areas of concern that are unique to a particular system, such as a user who intermittently uses power at a rate that overloads the system, affecting many other users.

1.5.2 Recorder Types. Common instruments used in a demand billing system are a rate recorder such as the one illustrated in Figure 10-2, or a circular recorder, as shown in Figure 10-9. Circular recorders are not highly effective if data reduction is required and have been replaced with a data logger with reduction by microprocessor program. These devices record the use rate continuously. Peaks are easily detected over the period of recording. If a recorder is used, the preferred type is a linear tracking, multichannel recorder. One advantage of this system is that the chart becomes a permanent record in case of customer disagreement concerning subsequent billings.

1.5.3 Alarm Actuator. A unique variation of chart recorders is shown in Figure 10-10. In this application the utility installs an instrument with a recorder onto user equipment. The agreement with the user is that severe penalties will be levied each time the use exceeds a predetermined rate. In an effort to avoid the penalty, a two-point alarm actuator is installed with an alarm programmed to respond at some warning point before the limit is reached, and then to initiate action if the limit is exceeded.

1.5.4 Alarm With Totalizer. Another variation of a use rate and penalty system is shown in Figure 10-11. This approach places a penalty (generally a unit price increase) on all consumption exceeding the limit. This is accomplished by employing an alarm actuator and using a totalizer to record the excessive usage.

2. SYSTEM COMPONENTS.

2.1 Meter Energy Usage. Although each medium requires a specific type of meter, all meters must have a signal-generating device to provide either onsite or remote data reading and recording capabilities. The meter q ust sample the media and transmit a representative signal to the system. Electric meters rely on the medium they monitor for energy to produce the monitoring signal. Turbine meters generate their own signal. Many meters rely on an outside source of electricity to produce a transmission signal.

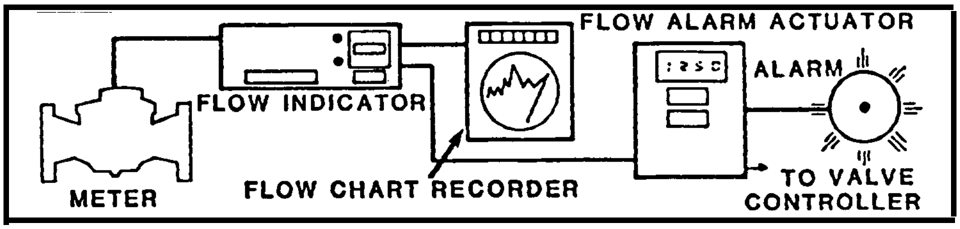


FIGURE 10-10. Alarm Actuator System

2.2 Signal Generators. Electronic or electromechanical signal generators are available that produce analog and/or digital signals for transmitting data to data processing equipment (onsite meters or recorders) or to a more complex remote system.

2.2.1 Analog Output. The analog output of a signal generator is a continuous signal representing the quantitative information obtained by the meter.

2.2.2 Pulse Output. A pulse output is a discrete series of pulses produced by the signal generator representing quantitative information.

2.3 Power Supply. Power supplies are a required part of many systems to supply low voltage in direct current (VDC) and low current in milliamperes (mA) for excitation of the signal generator. The low voltage and current is processed by the signal generator, producing an analog and/or digital signal, for transmission to the monitoring system.

2.4 Pulse Rate Converter. The pulse rate converter (PRC) is designed to interface between the meter pulse generating unit and measuring equipment. The device accepts low-level input frequency signals, processes the signals, and provides output signals that are proportional to the use rate.

2.5 Pulse Compensator. Pulse compensators are self-contained electronic modules which compensate the output pulse train of a meter with respect to a secondary process variable such as temperature, pressure, or density.

2.6 Frequency-to-Current Converter. The frequency-to-current converter (FCC) converts the pulse output from a meter or other transmitter into a proportional 4-20 mA current loop signal.

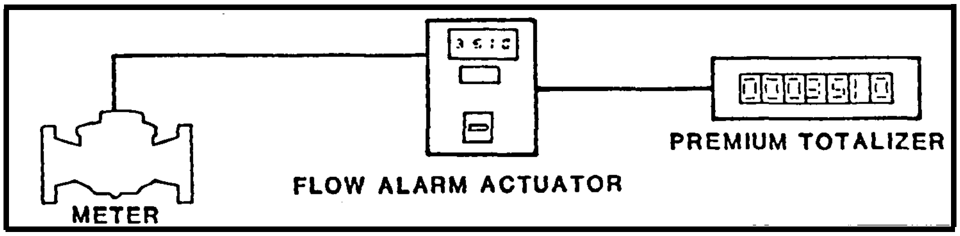


FIGURE 10-11. Alarm Actuator and Totalizer System

2.7 Repeater. The repeater is used to extend the distance the remote equipment can be located from the q eter. The repeater is located as close as practical to the meter. The repeater allows reduction of the electrical load on the meter generator electrical contacts, extending the life of the device. It also provides a strong signal to allow monitoring equipment at remote locations to be as much as several miles from the meter.

2.8 Accumulators. When it becomes necessary to place two or more q eters in parallel to satisfy a system requirement, an accumulator collects and combines data from these meters and transmits a totalized signal to the remainder of the system.

References

1. American National Standards Institute, C-12 Series Standards.
2. NAVMAT P-5100 Series, Navy Safety Precautions for Shore Activities, Naval Material Command.
3. NEESA 41-018, Criteria for Installation of Utility Meters at Navy Shore Activities, October 1984.

ABBREVIATIONS

AC	Alternating current
ASME	(American Society of Mechanical Engineers
CPR	Cardiopulmonary resuscitation
cps	Centistokes per second
CT	Current transformer
DC	Direct Current
DoD	Department of Defense
dp	Differential pressure
ECO	Energy conservation opportunities
EqT	Equivalent cam teeth
F	Fahrenheit
FCC	Frequency--to--current converter
gpm	Gallons per minute
hp	Horsepower
HVAC	Heating, ventilating, and air conditioning
Hz	Hertz
kVA	Kilovoltamperes
kVAr	Kilovoltamperes-reactive
kW	Kilowatt
kWc	Demand multiplier
kWh	Kilowatthour
LPG	Liquified petroleum gas
mA	Milliamperes
MBTU	Million British thermal units
pf	Power factor
pKh	Primary meter constant
PRC	Pulse rate converter
psi	Pounds per square inch
psig	Pounds per square inch gauge
PSR	Power survey recorder
PT	Potential transformer
PWC	Public Works Center
PWD	Public Works Department
SIR	Savings--to-investment Ratio
VAC	Volts alternating current
VAR	Voltampere-reactive
VDC	Volts direct current

BIBLIOGRAPHY

ASME
(1971) Application: Part 11 of Fluid Meters. American Society of Mechanical Engineers, 345 East 47th Street, New York, NY 10017

ASME
(1971) Fluid Meters: Their Theory and Application. American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, NY 10017

Bailey
(1983) Installation of Orifices and Flow Nozzles. Product Instruction G23-1. Bailey Controls, Wickliffe, Ohio 44092

Brown, Michael A., P.E.
(1982) A Survey of Energy Meters. Report DAAK 70-81-C-0916, JEMICO, Inc., Columbia, Maryland 21044. FESA-T-2125, U.S. Army Facilities Engineering Support Agency, Technology Support Division, Fort Belvoir, Virginia 22060

Casedy, Gary A.
(1982) Fluid Flow Meter Selection. Heating/Piping/Air Conditioning, May 1982

Crane
(1983) portable Sewer Flow Monitor. Crane Co., P.O. Box 191, King of Prussia, Pennsylvania 19406

Dranetz
(1983) Energy Survey Handbook for Electric Power Systems. Dranetz Technologies, Inc., P.O. Box 4019, Edison, New Jersey 08818-4019

Electro-Test Inc.
(1981) Electrical Metering Course. Course No. 1380620. Department of the Navy, Navy Public Works Center, San Diego, California

General Electric
(n.d.) Application of Watthour Meters. GET-1905D. General Electric Company, Meter and Instrument Business Department, Somersworth, New Hampshire 03878

General Electric
(n.d.) HOW to Test and Adjust General Electric A-C Watthour Meters. GET-813G. General Electric Company, Meter and Instrument Business Department, Somersworth, New Hampshire 03878

General Electric
(n.d.) Manual of Watthour Meters. GET-1840c. General Electric Company, Meter and Instrument Business Department, Somersworth, New Hampshire 03878

BIBLIOGRAPHY

Georgia Institute of Technology
(nod.) Energy Measurement Instrumentation and Techniques. Georgia Tech Research Institute, Georgia Institute of Technology, Atlanta, Georgia

IEEE
(1984) Metering and Measurement, IEEE Std-739-1984

Mahaffey, Dr. James A.
(n.d.) Electrical Power and Steam Consumption Metering Techniques. Technical Report for Project A-2891-000. Georgia Institute of Technology, Engineering Experiment Station, Atlanta, Georgia 30332

Mannion, James R.
(1982) Fluid Flow Meter Selection. Heating/Piping/Air Conditioning, May 1982

Marsh/McBirney
(n.d.) VMFM Flowmeter Marsh/McBirney, Gaithersburg, MD 20877

Messock, Richard K.
(1984) Criteria for Installation of Utility Meters at Navy Shore Activities. NEESA 41-018. Naval Energy and Environmental Support Activity, Port Hueneme, California 93043

NCEL
(1985) Steam Flow Meters in Navy Shore Facilities. NCEL Techdata Sheet 85-20. Naval Civil Engineering Laboratory, Port Hueneme, California 93043

NEESA
(1984) Electrical Metering Training Manual. NEESA 41-003 Revision A. Prepared by EMC Engineers, Inc. Naval Energy and Environmental Support Activity, Port Hueneme, California 93043

INDEX